Report Title:	Establishment of an Industry-Driven Consortium Focused on Improving the Production Performance of Domestic Stripper Wells
Report Type:	Final Technical Report
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DISCLAIMER

ABSTRACT

The Pennsylvania State University, under contract to the U.S. Department of Energy (DOE), National Energy Technology Laboratory (NETL), established an industry-driven consortium that is focused on improving the production performance of domestic petroleum and/or natural gas stripper wells. Industry-driven consortia provide a cost-efficient vehicle for developing, transferring, and deploying new technologies into the private sector. The Stripper Well Consortium (SWC) is a public/ private partnership between the U.S. stripper well industry (petroleum and natural gas producers and service companies), industry trade associations, academia, the National Petroleum Technology Office (NPTO), the New York State Energy Development Authority (NYSERDA), and the NETL.

During 2000-2003 funding cycles, the SWC membership has grown to 79 companies in 18 states and 2 foreign countries (Canada and Venezuela). The SWC technology development research has been focused in the areas of reservoir remediation, wellbore clean-up, and surface system optimization. During 2000-2003 funding cycle, the SWC Executive Council approved $3.39M to co-fund 38 projects. These 38 projects had a total projected cost of $5.66M. The process of having industry develop, review, and select projects for funding will ensure that the consortium conducts research that is relevant and timely to industry.

The SWC organized and hosted 6 technology transfer workshops and participated in 6 outreach workshops to showcase the SWC-funded technologies currently under development. In addition to the workshops, SWC members receive final technical reports upon the conclusion of each funding year. A total of 38 final reports have been distributed.

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EXECUTIVE SUMMARY

Stripper wells, by definition, are low-volume wells. The Interstate Oil and Gas Compact Commission (IOGCC) defines these wells as:

- ***Petroleum stripper well*** – a well that produces 10 barrels of oil per day or less;
- ***Natural gas stripper well*** – a well that produces 60 thousand cubic feet (Mcf) per day or less.

Although the individual production of these wells is low, together these domestic wells produce about 16 percent of the petroleum and 8 percent of the natural gas produced onshore. Table 1 summarizes the IOGCC stripper well data for the 2001-2003 timeframe.

Table 1. U.S. Stripper Well Summary (2001-2003)

	2001	2002	2003
Petroleum stripper wells			
# wells	403,459	402,072	393,463
Oil production (bbls)	316,099,192	323,766,606	313,748,001
Average daily production/ well (bbls)	2.15	2.21	2.18
Natural gas stripper wells			
# wells	234,507	245,961	260,563
Gas production (Mcf)	1,353,516,378	1,418,273,779	1,478,105,524
Average daily production/ well (Mcf)	15.8	15.8	15.5

The Pennsylvania State University, under contract to the U.S. Department of Energy (DOE), National Energy Technology Laboratory (NETL), established an industry-driven consortium that is focused on improving the production performance of domestic petroleum and/or natural gas stripper wells. Industry-driven consortia provide a cost-efficient vehicle for developing, transferring, and deploying new technologies into the private sector.

The Stripper Well Consortium (SWC) is a public/ private partnership between the U.S. stripper well industry (petroleum and natural gas producers and service companies), industry trade associations, academia, the National Petroleum Technology Office (NPTO), the New York State Energy Development Authority (NYSERDA), and NETL.

During 2000-2003 funding cycles, the SWC membership has grown to 79 companies in 18 states and 2 countries (Canada and Venezuela). The SWC technology development research has been focused in the areas of reservoir remediation, wellbore clean-up, and surface system optimization. The SWC technical advisory committee elects a 7-member Executive Council, which has staggered 2-year terms, which review projects for co-funding. Proposals must address improving the production performance of stripper wells and must provide a minimum of 30% cost share.

During 2000-2003 funding cycles, the SWC released 3 request-for-proposals that resulted in 72 projects being submitted to the Consortium for co-funding consideration. Of these 72 proposals, the SWC Executive Council approved $3.39M to co-fund 38 projects. These 38 projects had a total projected cost of $5.66M. The process of having industry develop, review, and select projects for funding will ensure that the consortium conducts research that is relevant and timely to industry.

Efficient technology transfer is critical for the deployment of newly developed technologies into the field. The SWC organized and hosted 6 technology transfer and participated in 6 outreach workshops. Numerous trade magazines and newsletters (e.g., American Oil & Gas Reporter, World Oil, Petroleum Technology Transfer Council) showcased a broad array of projects co-funded by the SWC. In addition, the SWC worked with Hart Energy Services to develop a technical bulletin entitled: "Keeping the Home Wells Flowing – Helping Small Independent Oil & Gas Producers Develop New Technology Solutions". This bulletin reviews the SWC and showcases 12 projects. The SWC also worked with Penn State Public Broadcasting to develop a public broadcast on the domestic stripper well industry, which also showcased several technologies being co-funded by the SWC.

EXPERIMENTAL

The DOE reporting guidelines require technical reports to contain a section on experimental methods. Because Penn State is responsible for the management activities of the SWC, this section is not applicable to the Penn State contracted activities. However, individual projects conducted during this reporting period are required to provide an experimental section. These project final reports are included in the Appendices of this report.

RESULTS AND DISCUSSION

This report represents the first final report for 2000-2003 funding cycle since the SWC inception on October 1, 2000. This report discusses the:

- Establishment of the consortium;
- Consortium membership;
- Process by which the SWC solicits and commits funding to projects;
- Number of funding requests submitted and approved; and
- SWC technology transfer and communications.

This report also contains the final reports for the various projects co-funded by the SWC.

Formation of Consortium

Penn State has organized the SWC to be industry driven. The inaugural meeting of the SWC was held on January 29, 2001 in Pittsburgh, PA. This meeting was dedicated to forming the SWC technical advisory committee, approval of the SWC Constitution, discussion of the technology development focus areas to form a SWC request-for-proposals (RFP), and the election of the SWC Executive Council. The SWC Constitution is provided in Appendix A.

Membership Overview

During this reporting period, the SWC had the following membership structure:

- **Full Members.** Members from any individual firm, partnership, university or corporation engaged in the production and/or service of the natural gas and petroleum industry;

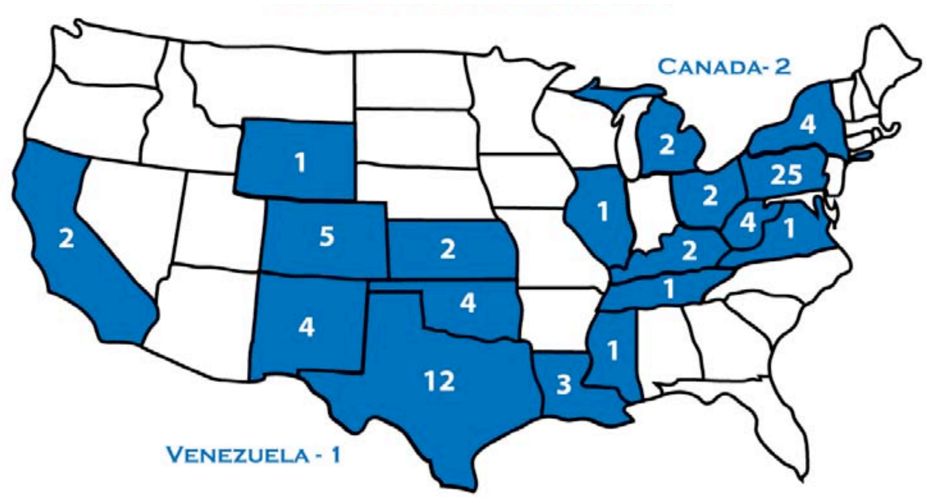
- **Affiliate Members**. Members from associations and professional societies; and

- **Endorsing Members**. Members from federal entities.

Each member company appoints one representative to a Technical Advisory Committee. The Technical Advisory Committee is responsible for steering the technical direction of the consortium and is responsible for electing seven voting members to the SWC Executive Council. The Executive Council voting members are responsible for selecting proposed research programs for funding. In addition to the seven elected Council members which have staggered 2-year terms, the Executive Council also has four standing non-voting members. These members include: one representative from the NETL Natural Gas Program, one representative from NETL Oil Program (formerly the National Petroleum Technology Office (NPTO)), one representative from New York State Research & Development Authority (NYSERDA), and the SWC Director.

The SWC has been growing and diversifying its membership since its inception. During the 2000-2003 funding cycles, the SWC membership grew to 79 members. This membership comes from 18 states in the U.S. and two countries outside the U.S. (Canada and Venezuela). The number of members from each state is depicted in Figure 1.

FIGURE 1. SWC Membership Map (2000-2003).



Technology Development

The development and deployment of new technologies to improve the production performance from domestic petroleum and natural gas stripper wells is at the heart of the SWC activities. The SWC seeks to identify new technologies that have broad applicability to the stripper well industry.

Technology development shall include, but not limited to, the following areas:

- Reservoir remediation, characterization, and operations;
- Well-bore clean-up; and
- Surface and collection optimization.

Requests-For-Proposals

The SWC issues a request-or-proposal (RFP) near the end of each calendar year and allows a nominal 90-day response period. The RFP process ensures the proposals are submitted in a consistent and acceptable format. During the 2000-2003 funding cycles, 3 RFPs were released. Appendix B contains the 2003 RFP which is very similar in content and requirements to those issued in 2001 and 2002.

The submittal process has been streamlined to be applicant friendly to the stripper well industry. Streamlining this process is important to the small independent stripper well operators which may not accustomed to submitting funding requests. Proposals are submitted to the SWC Director who compiles the funding requests and distributes them to the SWC Executive Council for their review. A proposal guideline evaluation form is supplied to the Council for use in their proposal review process. Members that seek co-funding are required to provide a minimum of 30% cost share to the project. Cost share is to be in the form of cash and/or in-kind support.

Project Selection

Applicants requesting co-funding from the SWC are required to attend the annual SWC spring meeting to present their proposal with the membership and Executive Council. Applicants are provided approximately 30-minutes to present their proposed work plan and to answer questions. This review process is an important operating element for the SWC because it stimulates a critical review of all projects requesting SWC co-funding.

Table 2 summarizes the dates, locations, and number of proposals reviewed for the annual spring meetings held during the 2000-2003 funding cycles.

TABLE 2. SWC Spring Meeting Summaries

Date	Location	Proposal Summary		
		# Submitted	Total Project Costs	Requested from SWC
2001 April 9-10	State College, PA	23	$3,544,529	$1,970,570
2002 March 12-13	Columbus, OH	22	$3,288,816	$2,083,742
2003 May 5-6	Pearl River, NY	27	$5,237,667	$2,997,622
	Total	72	$12,071,012	$7,051934

2001 Projects. Of the 23 proposals submitted to the SWC, the Executive Council recommended to provide $921,027 to co-fund 13 proposals which collectively provided 41% cost share. Appendix C contains the final reports for the remaining 12 projects.

2002 Projects. Of the 22 proposals submitted to the SWC, the Executive Council recommended to provide $1,337,374 to co-fund 13 proposals which collectively provided 36% cost share. One applicant withdrew their funding request prior to issuing their subcontract. Appendix D contains the final reports for these 13 projects.

2003 Projects. Of the 27 proposals submitted to the SWC, the Executive Council recommended to provide $1,131,000 to co-fund 12 proposals which collectively provided 43% cost share. Appendix E contains the final reports for these 12 projects.

Technology Transfer

Efficient technology transfer is critical for the deployment of newly developed technologies into the field. The SWC organized and hosted 6 technology transfer workshops to showcase the projects that it co-funded. In addition, the SWC participated in 6 additional outreach workshops. As the number of projects co-funded by the SWC increased and the SWC membership grew and diversified, the SWC needed to expand its technology transfer efforts throughout this reporting period. Table 3 provides a listing of these technology transfer workshops and outreach activities.

In addition to the workshops, SWC members receive final technical reports upon the conclusion of each funding year. To date, the SWC has released the final technical reports for projects funded in the 2001-2003 funding cycles. A total of 37 final reports have been distributed.

In addition, public abstracts for all of the SWC funded projects is available online at the SWC website (**http://www.energy.psu.edu/swc**).

TABLE 3. Technology Transfer and Outreach Meetings.

Date	Location	Description
2001		
October 24	Oklahoma City, OK	Industrial outreach meeting to build SWC awareness
October 25	Dallas, TX	Industrial outreach meeting to build SWC awareness
December 18	Hershey, PA	Formal SWC technology transfer meeting
2002		
July 10-11	Clymer, NY	Industrial outreach meeting to showcase SWC projects at IOGA-NY meeting
September 23	Erie, PA	Industrial outreach meeting to showcase SWC projects at annual POGAM meeting
October 17-18	Oklahoma City, OK	Formal SWC technology transfer meeting in collaboration with Oklahoma Marginal Well Commission
November 12-13	Mars, PA	Formal SWC technology transfer meeting in collaboration with IOGA-PA
2003		
September 15	Grove City, PA	Industrial outreach meeting to showcase SWC projects at annual POGAM meeting
October 2-3	Casper, WY	Formal SWC technology transfer meeting in collaboration with Rocky Mountain Oilfield Testing Center
October 30	Lubbock, TX	Formal SWC technology transfer
November 11	Buffalo, NY	Industrial outreach meeting to showcase SWC projects at IOGA-NY meeting
November 18	DuBois, PA	Formal SWC technology transfer

Communications

The SWC communication efforts have been on the ongoing since its inception. The SWC established a web site immediately upon its inception to disseminate information on the consortium and its associated activities. The web site is: http://www.energy.psu.edu/swc/

In addition to the technology transfer and outreach meetings, the SWC worked with Hart Energy Services to develop a technical bulletin entitled: "Keeping the Home Wells Flowing – Helping Small Independent Oil & Gas Producers Develop New Technology Solutions". This bulletin reviews the SWC and showcases 12 projects. A total of 3,000 copies were made and distributed.

The SWC worked with Penn State Public Broadcasting (WPSU) to develop and produce a public broadcast on the U.S. stripper well industry. The broadcast is entitled: "Independent Oil: Rediscovering America's Forgotten Wells". The broadcast is available on a multimedia DVD and is available upon request. A total of 2,500 copies were made and distributed.

In addition, a study on the use of laser, microwaves, and acoustics on stripper wells and petroleum and natural gas applications was conducted. This study is in Appendix F.

CONCLUSION

The SWC is a consortium comprised of petroleum and natural gas producers, service companies, industry trade associations, academia, the state and federal funding agencies. The SWC has worked hard to be recognized as a resource that stripper wells operators can draw upon to develop new, innovative technologies to improve the production performance of their wells.

Since its inception, the SWC has strived to grow in geographically diversify its membership. During 2000-2003, the SWC membership has grown to 79 companies. The geographic distribution of stripper wells in the lower 48 states is concentrated in about 28 states. The SWC has members from 18 of these states or about 64% of the states having stripper well production. The SWC now has a solid foundation by which its membership can be expanded further.

The research focus areas include: reservoir remediation, wellbore clean-up, and surface system optimization. These focus areas were defined at the onset of the Consortium by the membership and approved by the NETL. As the Consortium matures, the focus areas may be expanded to meet industry needs. During the 2000-2003 funding cycles, the SWC Executive Council approved $3.39M to co-fund 38 projects. These 38 projects had a total projected cost of $5.66M. The process of having industry develop, review, and select projects for funding will ensure that the consortium conducts research that is relevant and timely to industry.

The transfer of the technologies from these projects is at the core of the SWC activities. The SWC strives to collaborate with existing organizations (e.g., Oklahoma Marginal Well Commission, Independent Oil & Gas Associations, Petroleum Technology Transfer Council regional offices, Rocky Mountain Oilfield Testing Center, etc.) to showcase newly developed technologies. The SWC has utilized a mix of different technology transfer approaches including:

- Formal technology transfer meetings;
- Outreach meetings;
- Exhibiting at stripper well industry technology expos; and
- Printed technical bulletins;

The start-up time for consortia to develop new technology is approximately 18-24 months. The fruit of the SWC research efforts are now beginning to be deployed within the stripper well industry. This gradual deployment will continue in the upcoming years as the projects now being conducted are completed.

REFERENCES

2005 Report on Marginal Oil and Natural Gas: American Energy for the American Dream, Interstate Oil & Gas Compact Commission, Oklahoma City, OK., 46 p.

APPENDICES

This reports provides a majority of its reporting in an Appendix form due to the length and nature of the organizational and final report documents. The following data are listed in:

Appendix A: SWC Constitution

Appendix B: SWC Request-For-Proposals

Appendix C: 2001 Project Final Reports

Appendix D: 2002 Project Final Reports

Appendix E: 2003 Project Final Reports

Appendix F: Task 5: Applications of Lasers, Microwaves, and Acoustics to Stripper Wells and Oil/ Gas Applications

APPENDIX A:
SWC CONSTITUTION

CONSTITUTION FOR STRIPPER WELL CONSORTIUM

Article I

Name and Purpose:

Section 1. The name of this organization shall be the Stripper Well Consortium (SWC).

Section 2. The mission of the SWC is to assist in the development, demonstration, and commercialization of technologies to improve the production performance of the nation's natural gas and petroleum stripper wells. Its functions shall pertain to petroleum and natural gas science and engineering, and the dissemination of new information to the scientific community, industry and the general public. The organization shall serve its Members by guiding, stimulating, and aiding their efforts to:

i) formulate research, development, and technology assessment goals;

ii) create a supporting infrastructure for conducting research and development that will increase knowledge of and expand the technological base for natural gas and petroleum; and

ii) promote and enhance the dissemination of research results and technology transfer to industry for the benefit of the nation.

Section 3. The SWC and Members who are not participants in a project are not liable in any way for any activities under a given project.

Article II

Membership:

Section 1. Membership in the SWC shall be at one of three Membership levels:

(i) Full Members are defined as those Members from any individual firm, partnership, university or corporation engaged in the production and service of the natural gas and petroleum industry, or individuals engaged in research and development technologies associated with petroleum or natural gas industry or is a user of petroleum or natural gas products and who have provided an annual membership fee to be determined by the Executive Council. Full Members are entitled to designate one (1) voting representative to the Technical Advisory Committee, receive periodic communications, to compete for a seat on the Executive Council, to sponsor or propose a project for Consortium funding, and to receive quarterly and final technical reports. Full Members are eligible to have up to two (2) people in attendance at meetings. Only Full Members are eligible to receive research funding from the Consortium.

(ii) Affiliate Members are defined as those Members from associations and professional societies. Affiliate Members are entitled to designate one (1) voting representative to the Technical Advisory Committee, and to receive periodic communications. Affiliate Members are eligible to have up to two (2) people in attendance at meetings. Affiliate Members are not eligible to receive research funding from the Consortium, may not be elected to the Executive Council, nor are they eligible to receive technical reports. If however, an Affiliate member provides co-funding in support of a specific project, the Affiliate member is eligible to receive the technical reports associated with the specific project. The annual Membership fee for Affiliate Membership will be determined by the Executive Council.

(iii) Endorsing Members are defined as those Members from federal entities. Endorsing members may send up to two (2) representatives to meetings upon payment of a meeting registration fee. Endorsing Membership will be considered for those federal entities which provide a letter of endorsement to the Consortium that outlines the in-kind services the entity will provide to the Consortium. Endorsing memberships are subject to Executive Council approval.

Section 1a. Full, Affiliate, and Endorsing Members may withdraw from the Consortium upon thirty (30) days written notice to the Consortium Director. Membership fees are nonrefundable.

Article III

Organization and Officers:

The SWC shall be governed and managed by an Executive Council and the Consortium Director.

Section 1. The Executive Council shall be the policy-making body of the Consortium. The Executive Council shall establish an overall research and development plan for the SWC; approve and issue requests for proposals from Full Members to fulfill research and development priorities; establish review procedures for research proposals; select proposals to be funded from Consortium funds based upon the relevance to the established goals and objectives of the Consortium; and perform the duties necessary to achieve the SWC mission. The Director and various committees derived from the Executive Council Membership shall be utilized as deemed necessary by the Executive Council to achieve these and other Executive Council goals.

Section 1a. The Executive Council shall be composed of:

(i) seven (7) Full Members elected by the Technical Advisory Committee;

(ii) the SWC Director, who shall be a non-voting member presiding over the Council;

(iii) a representative from NETL's Strategic Center for Natural Gas (SCNG), who shall be a non-voting member of the Council;

(iv) a representative from NETL's National Petroleum Technology Office (NPTO), who shall be a non-voting member of the Council;

(v) a representative from the New York State Energy Development Authority (NYSERDA), who shall be a non-voting member of the Council;

(vi) a minimum of one natural gas producer;

(vii) a minimum of one petroleum producer;

(viii) a maximum of two universities;

(ix) council representation shall be such that a broad range of industrial interests is represented.

Section 1b. With the advice and consent of the Executive Council representatives, the SWC Director shall set the time, place and agenda of the Executive Council meetings and shall preside over these meetings. Whenever possible, telephone conferencing will be scheduled to conduct meetings. Executive Council Members shall be responsible for their own travel and other expenses associated with the performance of their responsibilities.

Section 1c. Representatives of the Executive Council who will be unable to attend the Executive Council meeting shall notify the Director as far in advance as possible. An Executive Council Member can vote in absentia provided it is done in a written form.

<u>Section 2</u>. The Technical Advisory Committee shall provide research ideas, and aid the Executive Council in developing and implementing technology transfer plans for the SWC. The Technical Advisory Committee shall advise both the Executive Council and the Director regarding the relevance and the scientific merit of the Consortium research and development programs.

Section 2a. The Technical Advisory Committee shall be composed of one (1) voting representative from each Full or Affiliate SWC Member.

Section 2b. The Technical Advisory Committee shall elect seven (7) industrial representatives to serve on the Executive Council. In the initial year, the Technical Advisory Committee shall elect four (4) representatives who shall serve a two-year term and three (3) who shall serve a one-year term. Thereafter, the Technical Advisory Committee shall elect three (3) representatives each year to replace outgoing representatives. No representative can serve two consecutive terms except for the one-year term representatives elected in 2001. The Technical Advisory Committee may also at any time elect a new representative to complete the term of a representative who is unable to finish his/her term.

Section 2c. With the consent of the Technical Advisory Committee, the Executive Council may be expanded to a nine (9) Members pending a 50% simple majority vote.

Section 2d. With the consent of the Technical Advisory Committee pending a 50% simple majority vote and unanimous approval of the SCNG and NPTO representatives, the Executive Council may be expanded to include those Affiliate member(s), which provide co-funding to the Consortium. The Affiliate member(s) shall be a non-voting member of the Executive Council. Terms of Affiliate member(s) serving on Executive Council will be determined on a case-by-case basis by the SWC Director and Council Representatives from SCNG and NPTO.

Section 3. The SWC Director shall be the chief representative of the Consortium and shall be responsible for the administration of its affairs. The Director shall represent the Consortium in situations where a single representative of the Consortium is appropriate. The Director shall interact with public and private funding sources to secure and maintain funding necessary to meet the long-term goals of the Consortium.

Section 3a. As the SWC Administrator, the Director shall implement the decisions of the Executive Council, and oversee the daily operations of the Consortium. The Director will establish and enforce computerized and other necessary communication systems among all Consortium Members. Under the direction of the Executive Council, the Director in accordance with Article V, will operationally manage Consortium funding. The Director will have authority to establish and maintain research reporting procedures, using sponsor guidelines where applicable. The Director shall publicize the SWC and its research results utilizing publications, research reviews, and any other means approved by the Executive Council. The Director will make frequent formal recommendations to the Executive Council to aid it in setting policy for the SWC.

Section 3b. The Director is appointed by The Energy Institute with the approval of The Pennsylvania State University, and serves at the pleasure of The Pennsylvania State University.

Section 4. Administrative costs of the Director and Director's office will be borne by the Consortium in accordance with the budget.

Article IV

Amending the Constitution:

Section 1. The Constitution can be amended only by the Executive Council. All changes to the Constitution must be approved by a two-thirds majority vote of the Council.

Section 1a . Any Executive Council member may propose a change to the Constitution or Bylaws by petition to the Director. The Director shall submit the proposed amendment or change to each representative of the Executive Council at least thirty (30) days prior to the next meeting.

Section 2. Unless indicated otherwise in the Constitution or Bylaws, all decisions for and on behalf of the Consortium shall be by consensus vote of those present in an Executive Council meeting. All votes shall be open ballot unless a majority of the Executive Council or Advisory committee prefers a closed ballot.

Article V

Program Funding:

Section 1. The SWC Director will solicit proposals from the Full Members of the Consortium on an annual basis. Membership dues must be current prior to accepting a proposal for review.

Section 2. The Consortium shall have no obligation or responsibility to consider any proposal requesting funding for third parties who remain outside of the Consortium. The Consortium does encourage collaboration among the SWC Members. Funding requests for third parties who remain outside the Consortium will be evaluated by the Executive Council on a case by case basis.

Section 3. Full Members are expected to provide a minimum of 30% in co-funding for each proposal submitted to the Consortium for review. All co-funding included must be supported by appropriate documentation and will be subject to review as part of the complete proposal package.

Section 4. The Director shall receive proposals from the Full Members and distribute the proposals to the Executive Council fourteen (14) days before the Consortium meeting.

Section 5. The Executive Council is the final decision making body for approval of all projects funded by the SWC.

Section 6. The SWC Director will notify all applicants of their funding status in writing within fourteen (14) days of the Executive Council decision.

BYLAWS FOR THE STRIPPER WELL CONSORTIUM

I. Purpose

These Bylaws are intended to promulgate the governing policies of the Consortium and shall be subject to and interpreted consistent with the Consortium Constitution.

II. Full and Affiliate Membership

1. Applications for Full and Affiliate Membership shall be submitted to the Director, whose responsibility it shall be to ensure their completeness and compliance with these Bylaws.
2. Upon receipt of Membership fee, the member(s) shall immediately exercise all rights, privileges and responsibilities of Membership.
3. Calendar year shall mean January 1 to December 31.

Any individual, firm, partnership, association, institution/university or corporation engaged in the exploration and production of natural gas and/or petroleum, or engaged in research and development of technologies associated with natural gas and/or petroleum, or is a user of natural gas and/or petroleum is eligible for Membership.

Membership in the Stripper Well Consortium entitles each Full Member to one (1) voting representative to the Technical Advisory Committee, periodic communications, eligibility of industrial Members to be elected to the Executive Council, eligibility to sponsor or propose a project, and eligibility to be awarded a research project from the Consortium. Affiliate Membership entitlements are as indicated in the constitution.

III. Endorsing Membership

1. Applications for Endorsing Membership shall be submitted to the Director, whose responsibility it shall be to ensure their completeness and compliance with these Bylaws.
2. Calendar year shall mean January 1 to December 31.

Endorsing members are not eligible to compete for Consortium funding. Endorsing Membership entitlements are as indicated in the consortium.

IV. Director

The office of the Director shall be located on the campus of The Pennsylvania State University, whose responsibility it shall be to provide an office, staff and facilities for the conduct of his or her duties and responsibilities as provided in the Constitution and these Bylaws. The administrative costs of the Director's office shall be borne by the budget of the Consortium.

The Executive Council shall meet at least twice a year at places and times set by the Director with the approval of the Executive Council representatives.

The Director shall prepare the agenda for Executive Council meetings from items submitted by the representatives of the Executive Council and the Technical Advisory Committee. He or she shall preside over Executive Council meetings and arrange for minutes of the meetings to be recorded and distributed to all Members.

The attendance of a majority of the representatives to the Executive Council shall constitute a quorum for the conduct of business at properly called meetings.

In the event that specific items of Consortium business require a vote of the Executive Council and it is impractical to convene a full Executive Council meeting, the Director will poll the Executive Council Membership by phone, computer, or other means.

V. Publications and Conferences

The preparation, presentation and publication of overview articles for SWC projects shall remain the responsibility of The Pennsylvania State University. Full Members shall be provided with the opportunity to review any overview papers or presentations containing any of the results of the SWC funded projects. Full Members may present technical papers on their SWC funded projects provided that the Consortium is acknowledged for its funding.

The Director shall be responsible for the preparation of all guidelines for technical reports and publications that have been approved by the Executive Council.

The Director shall arrange for all technical meetings and conferences at times and places approved by the Executive Council.

VI. Finances

The Pennsylvania State University will serve as fiscal agent for the Consortium. As such, The Pennsylvania State University will represent the Consortium in fiscal matters and have the ultimate accounting and financial reporting duties and the sole legal authority to enter into contracts and to administer and expend funds on behalf of the Consortium. The Members, acting solely upon their own behalf, may only subcontract with other Members, each likewise acting solely on its own individual behalf, for work conducted outside the member's institutions. The subcontracts will be carried out in accordance with the rules and regulations of research sponsors and standard internal subcontracting policies and procedures of the Members' institution as they may separately negotiate.

INTELLECTUAL PROPERTY RIGHTS POLICY FOR STRIPPER WELL CONSORTIUM

(Note: DOE Cooperative Agreement DE-FC26-00NT41025 was accepted by Penn State contingent upon the following language being incorporated in a subsequent modification.)

Pursuant to Chapter 18 of Title 35 of the United States Code, commonly known as the Bayh-Dole Act, as enacted by the Department of Energy (DOE) in DEAR 952.227-11, any domestic small business firm or nonprofit organization conducting research under Consortium funding (Research Party) may elect to retain title to any invention conceived of or first actually reduced to practice by its employees in the course of or under the research conducted with Consortium funding. Title to these inventions will be subject to DOE patent policy, including retention by the Government of a license for Government use and march-in rights, and U.S. competitiveness and manufacture requirements. The Consortium will petition the DOE for a class waiver of ownership rights to any inventions conceived or first actually reduced to practice by employees of entities other than domestic small business firms and nonprofit organizations. Information that results from the research and development conducted with Consortium funding and that would be trade secret or commercial or financial information that is privileged or confidential if the information had been obtained without Federal support, may be protected from public disclosure for up to five years after development of the information, but shall be available to Consortium Members during the period of projection.

APPENDIX B:

SWC REQUEST-FOR-PROPOSALS

REQUEST FOR PROPOSALS FOR THE STRIPPER WELL CONSORTIUM

Eligibility
Competition is open to all current Full Members of the Stripper Well Consortium (SWC).

University employees eligible to serve as principal investigators for consortium projects are:

Full-time regular tenure-track and regular faculty
Persons with the title of Research Assistant, Associate, Scientist or Senior Scientist

Research Focus Areas
The mission of the SWC is to assist in the development, demonstration, and commercialization of technologies to improve the production performance of the nation's natural gas and petroleum stripper wells. Proposals are being solicited from the SWC Full Members in the following three focus areas:

Reservoir remediation, characterization, and operations
Examples include, but are not limited to, the identification of by-passed reservoirs/ zones, stimulation/ recompeletion of existing wells, and mitigation/ reduction of water production

Well-bore clean-up
Examples include, but are not limited to, dewatering, down hole separation and injection, and removal of solids such as salts, scale, and hydrocarbon precipitation.

Surface and collection optimization
Examples include, but are not limited to, disposal/ utilization of solid-liquid waste streams (e.g. brine), surface treatment/ measurement of gas, and pipeline usage/ maintenance and compression.

Awards
Awards will be made on an annual basis. Subcontracts will be issued from The Pennsylvania State University to the successful applicant. The period of performance for this year's funding will be from July 1, 2003 to June 30, 2004. Members will be permitted to submit future proposals to extend the proposed work; however, this must be performed on an annual basis.

If additional documentation is required prior to issuance of a subcontract, a delay in submission of the July 1 start date may occur.

Submission
The final deadline for receipt of proposals is 4 PM on April 18, 2003. Proposals submitted after the deadline will be returned to the applicant. A signed original and twelve (12) copies along with a electronic copy of the executive summary should be submitted to the SWC Director at the following address:

Mr. Joel L. Morrison
Director, Stripper Well Consortium
The Pennsylvania State University
C-211 Coal Utilization Laboratory
University Park, PA 16802-2323

In addition to the proposal, each applicant is required to provide the SWC a nominal 20-minute presentation on the proposed project. The applicant is required to provide their presentation prior to the meeting. Presentations may be submitted with the proposal(s) but must be received no later than April 28, 2003.

Proposal Format
The format for your SWC proposal follows. The proposal should be on standard 8 1/2" x 11" letter size paper with 1" margins, each copy to be three hole punched and clipped. Please do not staple the proposal. Each page of the proposal should be numbered at the bottom. The type size must be clear and legible, in standard size, 12 points. No smaller than 10 point font size will be accepted with double line spacing.

Sections of the Proposal
The proposal shall consist of the following sections in order.

Cover Sheet See Attachment B
The cover sheet along with the executive summary will be distributed to the SWC membership as part of the proposal evaluation process.

Table of Contents One (1) page maximum

Executive Summary One (1) page maximum
Provide a one-page summary of the proposed research. The executive summary will be distributed among the SWC membership. An electronic copy of the executive summary is required. The summary should be written in the third person and include a statement of objectives and methods to be employed. It should be informative to other persons working in related fields and understandable to a scientifically or technically literate lay reader.

Project Description Five (5) page maximum

The main body of the proposal should outline the plan of work, including the broad design of activities to be undertaken. At a minimum the following should be discussed:

- Statement of the problem;
- Objectives and expected significance of the research;
- Statement of the work plan;
- Relation of the proposed work to comparable work in progress;
- Description of available facilities and major items of equipment available for the work; and reference citations.

Project Schedule One (1) page maximum

A plan which establishes the time schedule for accomplishing the work. The plan should include major milestones of the project in bar chart format and should cover the complete period of performance.

Anticipated Results One (1) page maximum

Discuss the commercialization viability of the proposed project. Discuss how the project will improve the production performance of domestic natural gas/ petroleum stripper wells. Identify any specific groups in the commercial sector that will use the projected results.

Budget See Attachment C

The submission of a reasonable budget is an important part of the proposal. Your budget may request funds under any of the categories listed on Attachment B so long as the item and amount are considered necessary to perform the work. Proposed equipment expenditures must be justified and are subject to program sponsor approval.

Cost-Share Commitments

A minimum of 30% cost-share is required. Applicants are encouraged to provide more than 30% cost share. The Executive Council will be tracking the level of cost share provided in each project. Cost share, which may be in the form of cash and third party in-kind, are acceptable as part of the matching if they meet the following criteria:

- Are verifiable, necessary and reasonable for proper and efficient accomplishment of the project;
- Are incurred within the project performance period, previously expended research, development, or exploration costs are unallowable.
- Are not included as contributions for any other federal project, are not paid by the Federal Government under another award, and be otherwise allowable in accordance with applicable Federal cost principles and DOE regulations governing cost sharing.
- The value of patents and data contributed to the project is unallowable as cost sharing.

All cost-sharing commitments must be supported by appropriate documentation. Failure to provide appropriate documentation can result in the proposal being returned without review.

Biographical Sketches One (1) page per person maximum
Each vitae should include educational background, professional experience, research interest, honors and professional activities.

Collaborative Work
All collaborations with individuals not included in the budget should be described and documented with a letter from each collaborator.

Other
Letters of support from outside sources are encouraged, but not mandatory.

Treatment of Proprietary Information
Privileged or confidential commercial or financial information that the applicant does not want disclosed to the public or used by the Government for any purpose other than application evaluation, should be specifically identified by page on the proposal cover sheet.

Proposal Evaluation/Review Process
The SWC Executive Council will review and select projects for SWC funding. The SWC Director will notify all applicants within fourteen (14) working days of the SWC meeting, by letter, of the final decision regarding their proposals.

Reallocation of Funds/ Project Modifications
Recipients of SWC Awards will have substantial discretion to reallocate funds should changing conditions demand it. Requests for budget revisions and/or project extensions shall be submitted in writing to the SWC Director.

Additional Information
Additional questions should be forwarded to the SWC Director. Questions should be submitted via e-mail to swc@ems.psu.edu or contact Mr. Joel Morrison at (814) 865-4802.

ATTACHMENT A - CHECKLIST

PI ___________________________

Project Title ____

To assure that your application is complete, please complete and paper clip (one copy only) the checklist to the cover sheet of the original (signed) copy of the proposal. Be sure the following items are included in the following order.

________ Cover page completed and signed by PI and authorized representative.

________ Executive Summary (one page maximum)

________ Detailed description of the work proposed (five page maximum)

________ Project schedule (one page maximum)

________ Anticipated results/commercial potential (one page maximum)

________ Budget on specified form with justification as required

________ Cost-Share Commitments

________ Biographical Sketches (one page per person maximum)

________ Collaborative Documentation

________ Letters of Support

________ Required number of copies (original + 12)

________ Electronic copy of the Executive Summary

________ Presentation (required by April 28, 2003)

ATTACHMENT B - COVER SHEET

Proposal Submitted to: Stripper Well Consortium
The Pennsylvania State University
C-211 Coal Utilization Laboratory
University Park, PA 16802-2308

Date of Submission ____________________

Title of Proposal ____

Amount Requested from SWC $_____________________

Cost Share Commitments Cash $_________
(Minimum 30% Required)
In-Kind $_________

Total Project Costs $_____________________

Principal Investigator ____

Phone: _______________ Fax: ____________ Email ______________

Address: ____

Other Participants: ____

PROPRIETARY INFORMATION: Does this proposal contain Proprietary or Confidential Information?

_____ NO _____ YES (if yes, complete box below)

Notice of Restrictions on Disclosure and Use of Data

The data contained on pages ___________ of this proposal are submitted in confidence and contain privileged or confidential commercial and/or financial information. Such data may be used or disclosed only for evaluation purposes. If funded, the Government would have the right or use or disclose data from this project to the extent provided the DOE/PSU Cooperative Agreement. This restriction does not limit the Government's right to use or disclose data obtained without restrictions from any source, including the proposer.

Submitted by: Approved by:

___________________________ ___________________________
Signature of PI Authorized Representative

ATTACHMENT C - BUDGET

Name of PI: ______________________________

	REQUESTED SWC	COST-SHARE
Salaries and Wages List individually all personnel identified in the proposal. Include title and percent of effort NOTE: The use of undergraduate and graduate students is encouraged, and appropriate. The basis for proposed percent of effort or labor hours should be identified (historical hours, engineering estimates).	$____________	$_____________
Fringe Benefits	$_____________	$_____________
Materials and Supplies List types required and estimated costs. NOTE: State whether amounts proposed are based on catalog prices or other cost estimating.	$_____________	$_____________
Equipment Items exceeding $5,000 and 1 year's useful life are defined as permanent equipment. List item and dollar amount for each amount. Justify and/or provide quotation.	$_____________	$_____________
Travel (see Note 4) State the type and extent of travel and its relation to the project. Itemize by destination and estimated costs.	$_____________	$_____________
Publication/Information Dissemination Estimate costs of documenting, preparing, publishing and sharing research findings. Show estimates.	$_____________	$_____________
Other Direct Costs Itemize and justify. (*See note below)	$______________	$_____________
______________________________	$ _____________	
______________________________	$ _____________	
Facilities and Administration (F&A) Specify current rate(s) and base. Note: A copy of the negotiated agreement should be included with the proposal. If none exists, a disclosure of the contents of the rate should be made.	$______________	$_____________
TOTALS	$______________	$_____________

Attach up to two additional pages of justification covering all items.

*NOTES:

1) Purchased Services, consulting or subcontracts proposed to non-consortium members shall not be more than 2.5% of the SWC requested funding without the prior approval of the SWC program coordinator.

2) Subcontracts to current consortium members must be less than 50% of the requested SWC funding. Budgets and work statements from each subcontractor, in the format above, should be included.

3) Fees or profits will not be paid on any award resulting from this solicitation. Nor can fee or profit be considered as cost-sharing.

4) The Stripper Well Consortium will host two technology transfer workshops during the last quarter of 2003. The workshops will be held in the eastern US (to be determined - Pennsylvania/ New York/ Ohio/ West Virginia region) and in the southern US (to be determined – Oklahoma/ Texas/ New Mexico region). Recipients of SWC funding are required to provide a presentation on the status of their project at both the eastern and southern technology transfer meetings. The costs of attending these SWC technology transfer meeting are to be included in the travel budget.

APPENDIX C:

2001 PROJECT FINAL REPORTS

Chamber Lift- A Technology For Producing Stripper Oil Wells

during the Period 05/15/2001 to 11/30/2002

By

E. M. Petrof, T. A. Carmody, E. S. Eltohami, M. A. Adewumi,
P. M. Halleck, B. Miller, R. W. Watson

The Pennsylvania State University
The College of Earth and Mineral Sciences
The Department of Energy and Geo-Environmental Engineering
The Energy Institute
Bretagne, G.P., Lexington, KY

April 20, 2003

Work Performed Under Prime Award No. DE-FC26-00NT41025
Subcontract No. 2037-TPSU-DOE-1025

For
U.S. Department of Energy
National Energy Technology Laboratory
P.O. Box 10940
Pittsburgh, Pennsylvania 15236

By
The Pennsylvania State University
The College of Earth and Mineral Sciences
The Department of Energy and Geo-Environmental Engineering
The Energy Institute
Bretagne, G.P., Lexington, KY

DISCLAIMER

ABSTRACT

The largest expense associated with the operation of most stripper wells and many stripper gas wells is the lifting costs associated with the removal of fluids from the wellbore. To address this problem, a chamber-lift system was proposed as an alternative to conventional lift systems such as rod pumping. The process involves the injection of gas into the oil column via a small diameter tubing string that is set in the production tubing. The gas then displaces the accumulated fluid to the surface via the annular space between the injection string and the production string. The process is controlled using a sensor and motor valve located at the surface.

A project that called for a field demonstration of the process, the fabrication and testing of a laboratory prototype, and the modeling of the process using hydrodynamic computer model was initiated.

An experimental wellbore apparatus was constructed to simulate the chamberlift system. The laboratory model provided for the observation of reservoir fluids accumulating in the wellbore and the removal of these fluids with a surface compressor. Initial wellbore fluid levels, various wellbore pressure points and surface flow rates were generated as a function of different reservoir and injection gas pressures. Tests were conducted using mineral oil and crude oil obtained from the Big Sinking Field located in Kentucky.

The physical phenomena observed in the experiments are consistent with those reported in the literature for other types of gas-lift. The experimental data that are reported in this work will be used in validating the mathematical model. The work that remains includes additional field testing and mathematical modeling.

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1.0 INTRODUCTION

1.1 Introduction

When first drilled and completed, most wells will flow naturally due to high reservoir pressures. However, during the life of the well, the formation pressure will drop to a point where the flow of oil and gas will either cease or decline to the point where it is uneconomical to continue production. In most cases, as much as 60% of the original oil in place has yet to be produced. At this stage of production, employing artificial lift methods will allow for further economical production of the reservoir. Artificial lift is defined as any method employed in oil well production as a supplement to reservoir energy when the natural energy can no longer sustain production of crude oil from the reservoir to the surface [Osuji (1994)]. Approximately 90% of all oil wells in the world are produced with some kind of artificial lift technique [Chacin and Intevep (1994)]. The second most common method is gas lift, second to only the rod lifting method, which has been in use since the late 1800's.

Gas lift is separated into two main categories. These are the continuous and intermittent gas lift techniques. Continuous gas lift works by constantly injecting high pressure gas into the well to help force the formation fluid to the surface. This method is the more common and is used in wells around the world. However, once the reservoir pressure depletes to a certain point, continuous gas lift will not function, because rather than lift the fluid it will force the fluid back into the formation. At this point in the production life of the reservoir, intermittent gas lift can be a useful technique for continuing production. One intermittent gas lift scheme is referred to as the chamberlift system. There are two types of chamberlift systems. One type involves inserting a bottle-like structure into the largest pipe, which collects the fluids. The other type operates by inserting a dip tube through the smallest pipe and producing the fluids up through it. The purpose of the chamberlift system is to reduce the required flowing bottom hole pressure in order to permit the entry of formation fluids into the wellbore. This system is ideal for a mature reservoir which has the characteristics of low formation pressure and a high productivity index. The use of a chamberlift system offers many advantages over other artificial lift methods, but there are some disadvantages as well.

1.1.1 Types of Chamberlift Installations

There are two general types of chamber installations. These two types are the typical two packer chamber installation and the insert chamber installation [Brown, Vencil et al]. Both types have advantages and disadvantages. Generally, the type of chamber installation is determined by the type of well completion.

The two packer chamber installation uses the annular space for the accumulator. This type of chamber installation is installed to allow for large storage volumes of liquids with a minimum amount of back pressure on the formation. However, the bottom packer must be set just above the perforated interval or open hole completion [Brown, Vencil et al].

The insert chamber installation is usually made from pipe and is used instead of the two packer chamber installation. This type of installation is normally used and works best in wells which have an open hole completion or long perforated intervals. Its greatest benefit is that it takes full advantage of the input flow characteristics, especially the very low bottom hole pressure. However, its one disadvantage is that it is made small to fit inside of the casing string. Therefore, it will hold more volume than the same length of tubing, but not as much as the two packer installation [Brown (1980)].

A dip tube may also be inserted into an insert chamber installation. This addition will allow the point of gas injection to be much lower, hence allowing for more liquid production. During a normal production operation of this kind, the gas is injected down the annulus formed by the dip tube and the insert chamber and the liquid is pushed up through the dip tube and is produced at the surface through the tubing above the chamber.

There are a variety of other installations that are a variation of the two packer and chamber installations. These variations in design are used to deal with certain problems such as formation gas, sand removal, open hole wells, and ultra-slim well completions. One such variation is the reverse flow chamber installation. This new concept allows upward venting of all formation gas by injecting lift gas down the tubing string and producing the liquids up the annulus between the casing and tubing strings. This design allows the formation gas to vent into the tubing through the same opening where the fluids are produced. This method appears to be a good choice for wells with high formation gas-oil ratios [Brown (1980)].

Another variation is a special chamber installation for sand removal. In this installation, the standing valve is extended up to be located in the tubing string. This will give the sand ample space to settle around the standing valve, as the fluid enters the chamber through this opening, instead of actually plugging the valve. This also allows for the standing valve ball and seat to be washed clean of the sand when the chamber is emptied with the lift gas. It is suggested in this case to have the perforations kept as close to the top of the packer as possible. This installation has proven to be successful when other installations have failed because of excess sand production [Brown (1980)].

A one packer installation has been another variation that has been successful in open hole wells with small diameter casing. This installation has the advantage of the added volume compared to the insert chamber installation. Normally this installation will exceed the production of other intermittent installations, but it is not normally recommended because of its instability [Brown (1980)].

Another type of installation is inserting the chamber above the packers. This is done to prevent or minimize certain problems such as sand production. This variation has proven to work well, but its major disadvantage is that it contains less overall volume than the two packer or normal chamber installation [Brown (1980)].

Macaroni installations are used in wells that are completed with smaller than normal casing outside diameters (less than 3.5 inches). They are referred to as “macaroni” strings, because of their unusually small diameter. The diameter of these macaroni strings is limited to the maximum outside diameter of the casing string and the outside diameter of the gas lift valves. This type of installation works well for producing one or both sides of a parallel dual string. Separate gas controls for each string are common and it eliminates the problem of lifting both strings from a common source. The most common disadvantage of these macaroni installations is that the small tubing sizes limit the production capacity [Brown (1980)].

1.1.2 Chamberlift Installation Equipment

Converting a production well from a continuous gas lift system, or even from another artificial lift method, into a chamberlift installation is a rather simple operation. Even the conversion of a naturally producing well into a chamberlift installation does not prove to be a difficult task. The most difficult part of the transition is trying to optimize the chamberlift installation once it has been converted. As mentioned above, there are numerous types of chamberlift installations. It is up to the operator to decide which installation would work best for the given well completion type and formation conditions. However, the basic equipment needed for these installations is very similar, no matter which installation is chosen. The additional equipment includes: a surface compressor, gas lift valves, a standing valve and a differential valve (or the bleed valve). Also, depending on the type of chamberlift installation that is chosen, an insert chamber, an additional production tube or dip tube, and an additional set of packers could be required.

Based on the type of installation, a type of unloading valve must be chosen. Once this valve is chosen, they must be spaced up the well from the bottom, with spacing depending on the available operating gas pressure and kick-off pressure. An operating pressure must also be selected for the valve. This pressure will be affected by two variables: the available operating compressor pressure and the feed-in rate of the fluid into the wellbore. When setting this valve operating pressure, allow for 150-300 psi differential between the opening pressure of the valve and the total load in the tubing. Traditionally, the higher the differential, the higher the percentage of recovery [Brown (1980)].

A differential valve, used for the bleed valve, must also be selected. The selection of this valve is largely based on the gas to liquid ratio (GLR). The higher the GLR, the larger the opening should be on the valve. The differential on this valve should not be too high. Also, as wells start making water, it is crucial that the opening in this valve be large. The reason for this large opening is that the pressure across the valve must be maintained when the gas enters the tubing. It has been shown that a 5/16 inch bleed valve is not large enough to prevent pressure loss across the valve when the well has started to make water [Mukherjee et al (1986)].

Other equipment variations such as the size of the compressor, the injection pressures, the cycle times, the tubing inside diameter, the flowline inside diameter, and the separator pressure are well specific. Therefore, the well operators should tailor each variation to fit their specific well.

1.1.3 Chamberlift Installation Production Procedure

The following section describes the general procedure used when producing from a chamberlift installation. When the chamber is filled with formation liquid, the injection gas is introduced into the wellbore. This causes the chamber operating gas lift valve to open and the standing valve closes. The liquid in the chamber annulus is U-tubed into the dip tube and the tubing above the chamber to form the initial slug length. The liquid slug is then forced to the surface through the tubing above the chamber. Not all of the initial slug is produced because of injection gas breakthrough and the friction caused by the pipe walls. This results in liquid fallback during the production of the slug.

The reservoir pressure continues to build as the standing valve remains closed during the production of the liquid slug. Formation fluids continue to enter the annulus created by the chamber and the outer casing. However, the formation fluids can not enter the chamber while the standing valve is closed. After the liquid slug surfaces, the injection gas is turned off and the remainder is exhausted into the flowlines and the flowing bottom hole pressure in the chamber decreases. The standing valve opens when the pressure in the chamber becomes less than the formation pressure around and beneath the chamber. The liquid in the annulus flows into the chamber first, followed by the formation gas which has risen above the liquid. This process continues until the pressure in the chamber is equal to the pressure in the annulus at the level of the standing valve. When this occurs, the flow into the chamber ceases and the entire process is repeated [Winkler (1999)]. Depending on the well set-up, the gas can be either introduced into the annulus and the liquid is produced through the inner tubing or the gas can be introduced through the inner tubing and the liquid is produced up the annulus. Both methods have proven to work very successfully.

The volume of gas and pressure at which the gas is injected is dependant on numerous variables such as the depth of the producing zone and volume of liquid in the annulus. Also, the cycle time is dependant on the inflow characteristics of the formation.

1.2 <u>Discussion of the Problem</u>

In many areas of the world, the chamberlift installation has proved to be a very economical method for producing oil and gas. This is especially true in mature fields when the reservoir pressure has decreased to the point where the wells have ceased to flow naturally and most artificial methods will no longer work. Although this technology has been around for many year, the primary reason that the chamberlift installation has not gained widespread acceptance and usage in the oil and gas industry is because its highly transient nature has made it very difficult to model. Therefore, predicting the cyclic characteristics and the behavior of the whole production system is nearly impossible [Liao et al (1995)]. Another extremely difficult task is trying to optimize this system when it is installed in numerous wells within a field and there are only a few compressors available to supply gas.

The current design method of a chamberlift installation system is more of an art than a science. Therefore, most methods are based on empiricism and consist mainly of rules-of-thumb. Research in this area is rare compared to the area of continuous gas lift. White et al (1963) attempted to simulate the motion of a finite slug of liquid propelled to the surface by high injection gas. On the other hand, Brown and Jessen (1962) conducted extensive field testing in 1962 and to develop empirical relationships for intermittent gas lift. However, these two approaches had distinct discrepancies in their results and today most modern intermittent gas lift designs use Brown and Jessen’s relationships. Neely et al (1973) and Deschner and Brown (1965) conducted extensive work in attempting to optimize the intermittent gas lift system. Such things as time rate behavior of the casing gas pressure and volume, the flow of gas through a gas lift valve, the liquid slug velocity, the amount of liquid produced as well as the amount left behind, and the pressure gradients during the process where all variables that were studied [Neeley et al (1973)].

However, these studies did not take into account the effects of liquid density in their results. These tests were also conducted using the general intermittent gas lift concepts with a limited variation in liquid composition. They did not consider the idea of a chamberlift installation. Finally, most published experimental work, both in the laboratory and with field implementation, deals with the idea of high productivity index reservoirs with high liquid flow rates. There has not been much work done in the area of applying the chamberlift installation to reservoirs with low productivity index wells and extremely low flow rates (less than a few barrels produced per day, per well).

One of the most important parameters to determine, when optimizing the chamberlift installation system, is the well inflow capability. The well liquid production potential is determined by the static reservoir pressure and the productivity index. Knowing this productivity index, other variables such as optimum cycle time, injection pressure, and injection pressure levels can be calculated [Hernandez et al (1998)]. Currently, most chamberlift installations are not optimized, hence they do not achieve their full production potential. However, as a few cases have shown, when the chamberlift installation system is optimized, its production results are greater than other artificial methods used in similar situations.

1.3 Objective of the Investigation

The primary goal of this study is to optimize the chamberlift installation system for reservoirs with low formation pressure, low productivity index and low liquid production per well (less than a few barrels per day). This study will also consider various liquid compositions and reservoir pressures. In order to do this, an experimental wellbore apparatus was constructed to simulate the chamberlift production process. A test matrix was constructed to conduct several tests. With a given liquid composition and reservoir pressure, the injection gas pressure was varied in order to find an optimum ratio between the reservoir pressure and the gas injection pressure. Also, the tests were run using various volumes of liquid within the annulus in order to see how the results varied. Pressure measurements were taken at the top and bottom of the wellbore. Also, the liquid fall-back, which is a measurement of the system's overall efficiency, is measured within the apparatus.

Development of a broad database is another objective of this work. The results of this database can then be analyzed using various simulation models. The results from the model can be compared to the lab scale apparatus to see if there are any similarities. Furthermore, experimental studies at the scale model level will provide insight for developing an effective strategy for implementing the chamberlift installation at the field level.

2.0 LITERATURE REVIEW

2.1 Origins of the Chamberlift Installation

It is believed that air lift got its start when oil companies started experimenting with it in 1846 [Osuji (1994)]. Air lift continued to be successful until the mid 1920's when gas replaced air and gas lift became the most widely used application.[1] Early gas lift installations were used strictly for continuous flow, with the major pitfall being that only one gas injection point was used around the tubing string. This problem was later solved with the invention of numerous kinds of "kick-off valves" [Osuji (1994)].

Shortly after gas lift was introduced, intermittent gas lift was first used in the Seminole Field in Oklahoma in 1926 [Brown (1982)]. This method was fairly successful and led to a whole new way of approaching gas lift as an artificial lift method. It was found that the intermittent gas lift method worked well for depleted reservoirs which had pressures so low that continuous gas lift would no longer work.

However, it is unsure from the literature when the first commercial chamberlift instillation was used. Most authors would agree that this technology has been around for over 40 years. However, the literature suggests that the chamberlift installation technology has only been applied around the world for a little over twenty years [Gasbarri and Marcano (1999)]. As mentioned earlier, White et al (1963) and Brown and Jessen (1962) were the first two publications on the idea of intermittent gas lift. However, White et al's model results did not match the field results of Brown and Jessen's, causing a great need for research in this area.

Some years later, it was reported that the chamber installation was having rather phenomenal success in a few applications around the world. For example, some installations were lifting up to 400-500 barrels/Day from as deep as 11,000 feet. Another example was that a chamberlift installation was lifting 600-700 Barrels/Day from depths of 6000-7000 feet [Brown (1967)]. In most of these cases, extremely low bottom hole pressure readings were recorded. Therefore, when optimized, the chamberlift installation can prove to be very successful.

2.2 The Need for Chamberlift Installation Optimization

Since the first application of intermittent gas lift in the Seminole Field in Oklahoma, the use of this method has been extended around the world. There are numerous other case histories documented in the literature [Brown and Jessen (1962), White et al (1963), Deshner and Brown (1965), Brown (1967), Neeley et al (1973), Brown (1980), Brown (1982), Osuji (1994), Liao et al (1995), Hernandez et al (1998), Hernandez et al (1999) (Paper No. 053968), Hernandez et al (1999) (Paper No. 052124)]. However, there have only been a handful of cases where the chamberlift installation has been used. [Brown, Vencil et al, Hernandez et al (1999) (Paper No. 056664), Winkler (1999), Gasbarri and Marcano (1999),]. Even when this type of installation is used, the design for such a system has been determined by field experience, rules-of-thumb, trial and error, simplified design models, or any combination thereof. As stated earlier, the highly transient nature of the chamberlift installation or all intermittent gas lift methods, for that matter, have made it very difficult to predict the production outcome. Consequently, field optimization is difficult to achieve and maintain and the benefits of the chamberlift installation have not been fully realized. As previously mentioned, there are a few major factors that determine the optimization of the chamberlift installation. They include well inflow capability, venting of formation gas, determining the correct cycling time, and determining the optimum ratio between the gas lift pressure and the reservoir pressure.

3.0 EXPERIMENTAL APPARATUS AND PROCEDURE

3.1 Experimental Apparatus

A laboratory-scale wellbore model was constructed to simulate the gas lift phenomenon that takes place in a chamberlift installation operation (see Figure 3.1). The model was designed to permit liquids to be lifted to the surface, via the inner production tubing or dip tube, at various gas injection pressures. These parameters could be varied to simulate different reservoir conditions and liquid levels within the wellbore. Important design features incorporated into the apparatus include:

1. A dip tube was inserted inside of the production tubing to represent a type of insert chamber installation. The installation is designed so that the dip tube is a few inches shorter than the production tubing. As the fluid enters the wellbore, it ascends into both the dip tube and the annulus created between the dip tube and the production tubing. This annulus represents the insert chamber itself. The dip tube and production tubing were made of steel pipes connected with steel couplings.
2. A standing valve was placed below the chamber so that it remains open when the fluid is entering the wellbore. The standing valve then closes when the gas lift pressure is introduced into the system. This prevents the fluid from being pushed back into the reservoir.
3. Pressure transducer devices[1] were located at the top and bottom of the wellbore. These devices recorded the pressure in the annulus every half second, throughout the experiment. These devices were wired to a box (National Instrument) and emitted a voltage output which was converted to a pressure reading.

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1. Omega Engineering Inc., Stamford, CT

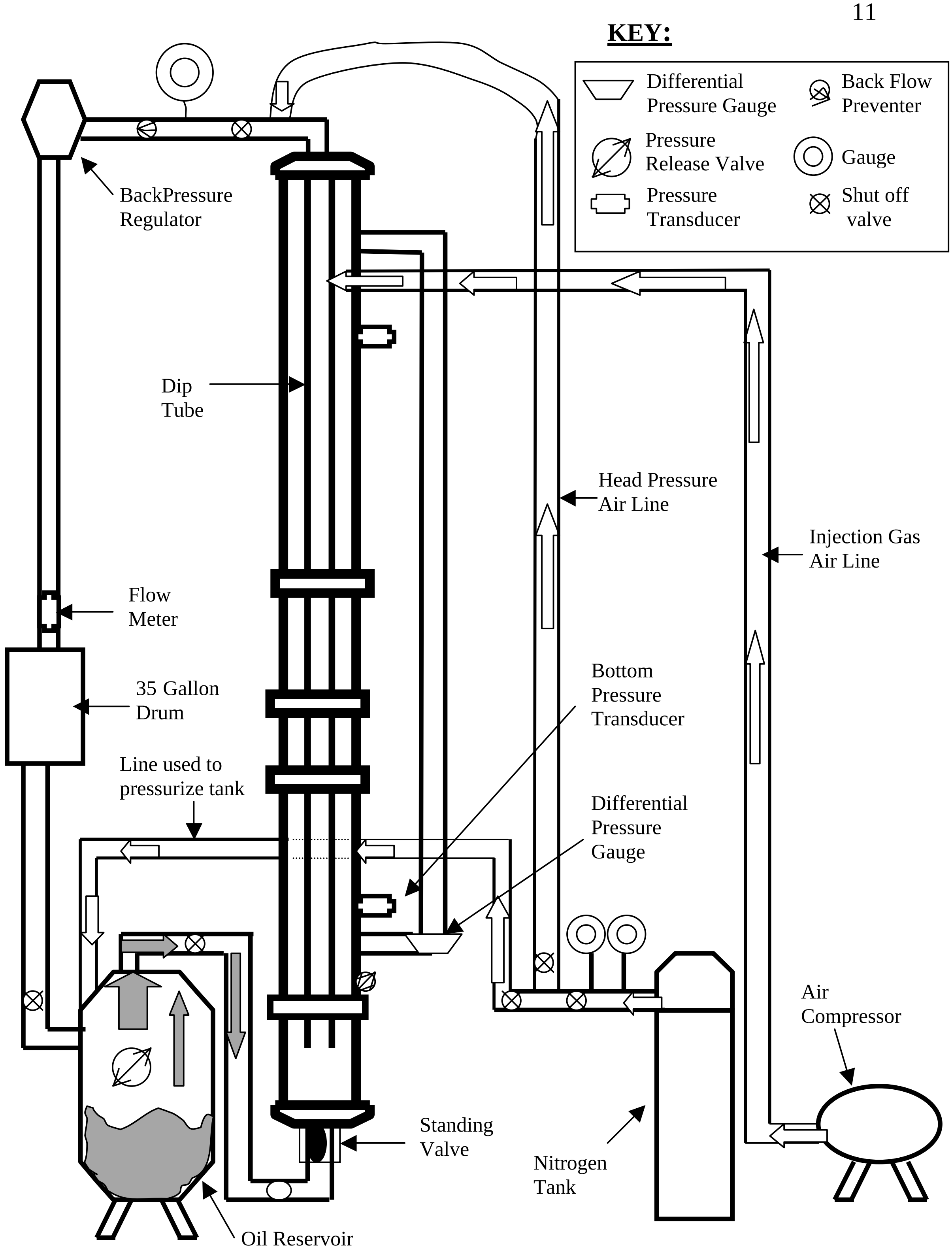

Figure 3.1: Schematic of Experimental Apparatus

4. A differential meter[1] was place on the wellbore to read the difference in pressure at the top and bottom of the apparatus. This device was also wired to the box and its output was converted to a pressure reading. This reading also gave a precise understanding of how much liquid was in the annulus at the start of the test.

5. A back pressure regulator[1] was placed at the surface to regulate the pressure within the wellbore. This allowed for a certain amount of pressure build-up, while the liquid entered the wellbore. The back pressure regulator was set in such a way that the device would not be overcome by the pressure inserted within the wellbore from the liquid entry, but it would allow flow once the gas lift pressure was introduced. The regulator would allow flow through it once the gas lift pressure was introduced, because this pressure was greater than that level of pressure required to overcome the regulator.

6. A flow meter[1] was placed at the surface to measure the flow of fluids being produced. This meter was placed within the string of pipe that connected the back pressure regulator and the barrel which collected the fluids. This meter was also wired to the box and the output was converted to gallons per minute of flow.

7. A pressurized tank was installed on the ground next to the wellbore. This tank was filled with liquids and pressurized to various levels to represent the production formation. The tank was connected to the bottom of the wellbore with various steel pipes and fittings.

8. A digital thermocouple[2] was installed at the midpoint of the wellbore to measure the temperature in the annulus at half second intervals. This temperature is necessary to determine the velocity within the wellbore at various times throughout the test.

The compressed air was supplied by a Grange Electronics compressor that was capable of delivering 1000 standard cubic feet per minute of air at 200 psig. The compressor had two pressure gauges mounted on it. One gauge was mounted on the back and measured the pressure that was built up within the compressor. The other gauge was mounted on the front of the compressor and measured the pressure of the air that was

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2. Omega Engineering Inc., Stamford, CT

exiting the compressor. Valves that controlled both gauges and the pressure levels could be easily changed. The compressed air flowed from the compressor up to the top of the wellbore via a half-inch high-pressure airline. The release of this air was controlled by an on/off valve, which connected a section of the high-pressure hose from the compressor with a high-pressure hose that ran up to the top of the wellbore.

The experimental wellbore consisted of two concentric steel pipes. The outer steel pipe acted as the insert chamber and the inner pipe acted as the dip tube. (reference Fig. 3.2). The overall vertical height of the wellbore was approximately 25 feet (reference Fig. 3.3). The outside diameters of the dip tube and the insert chamber were 1.05-inches and 1.995-inches, respectively. The volumes of the dip tube and the insert chamber were 0.093 and 0.30-cubic feet, respectively. In the experiments, compressed air flows up the high-pressured hose and into the annulus near the top of the wellbore. It then flows down the annulus to where the liquid is resident.

The wellbore was equipped with ports which tapped into the annulus of the wellbore. These ports were spread out in two to three foot intervals and allowed for pressure and temperature readings to be taken at various heights within the wellbore. The pressure transducers had ranges that varied from 0 to 250 psi and extended about 0.125 inches into the annulus to minimize interference with and damage from the high pressures and flow of liquids. The thermocouple was installed at the midpoint of the wellbore to measure the temperature in the annulus. The probe of the thermocouple also extended 0.125 inches into the annulus.

At the top of the wellbore, where the fluids exited the dip tube, a large swivel was used to connect the dip tube to another section of pipe that included a pressure gauge and back pressure regulator. The back-pressure regulator was a spring-loaded ball seat type. Therefore, fluids could enter from the side and the regulator would stop the flow until the pressure reached a present level. When this pressure was attained, the valve would bypass the fluids through the valve and out the bottom of the regulator. The bottom of the regulator was connected to a 35-gallon barrel by a 0.375 inch steel pipe. The drum would collect bypassed fluids during the duration of the experiment. The top of the barrel was open to the atmosphere. Venting the air to the atmosphere was done to prevent pressure build-up in the barrel to a point where failure of the barrel could occur.

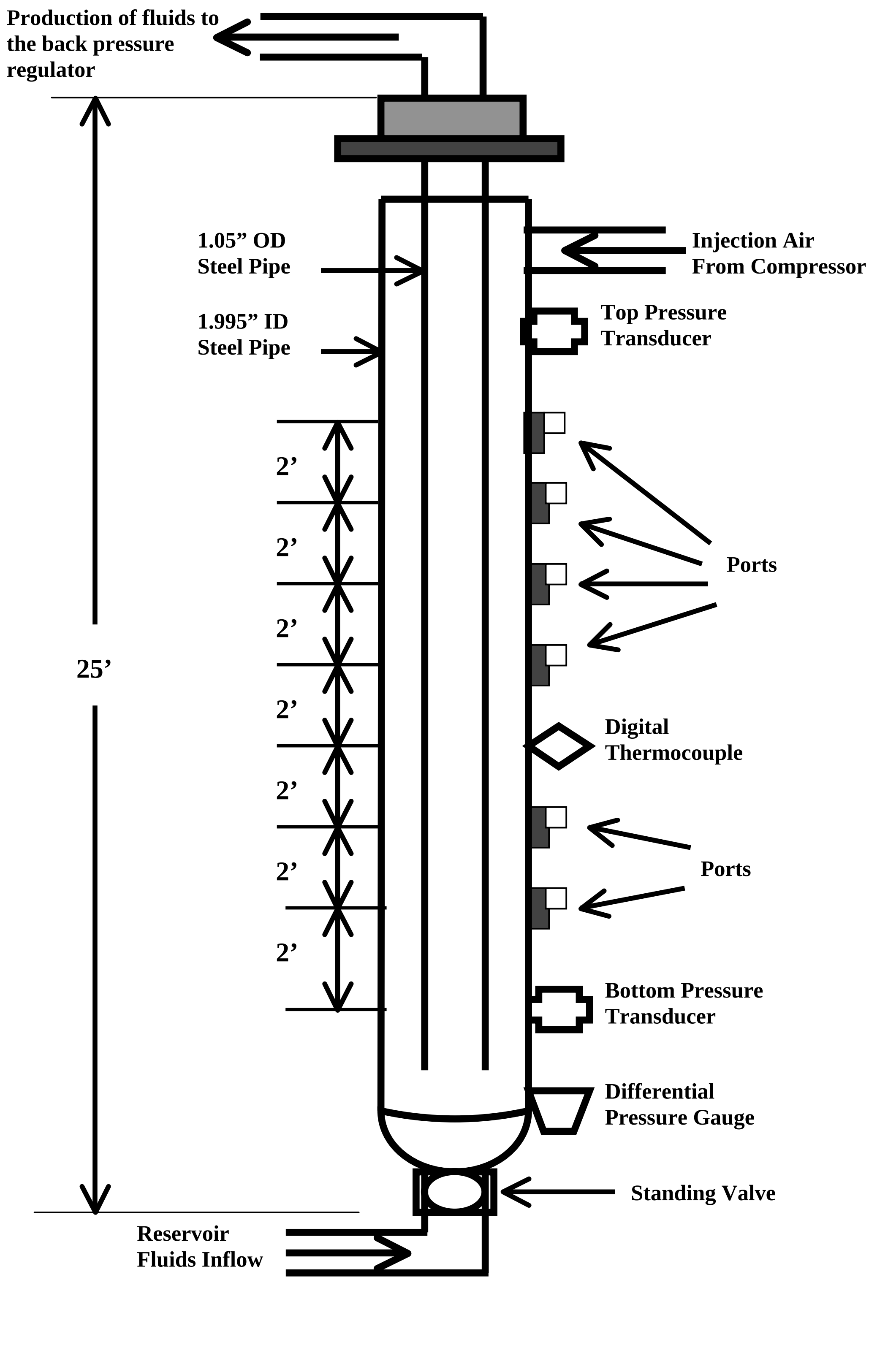

Figure 3.2: Detail of the wellbore section

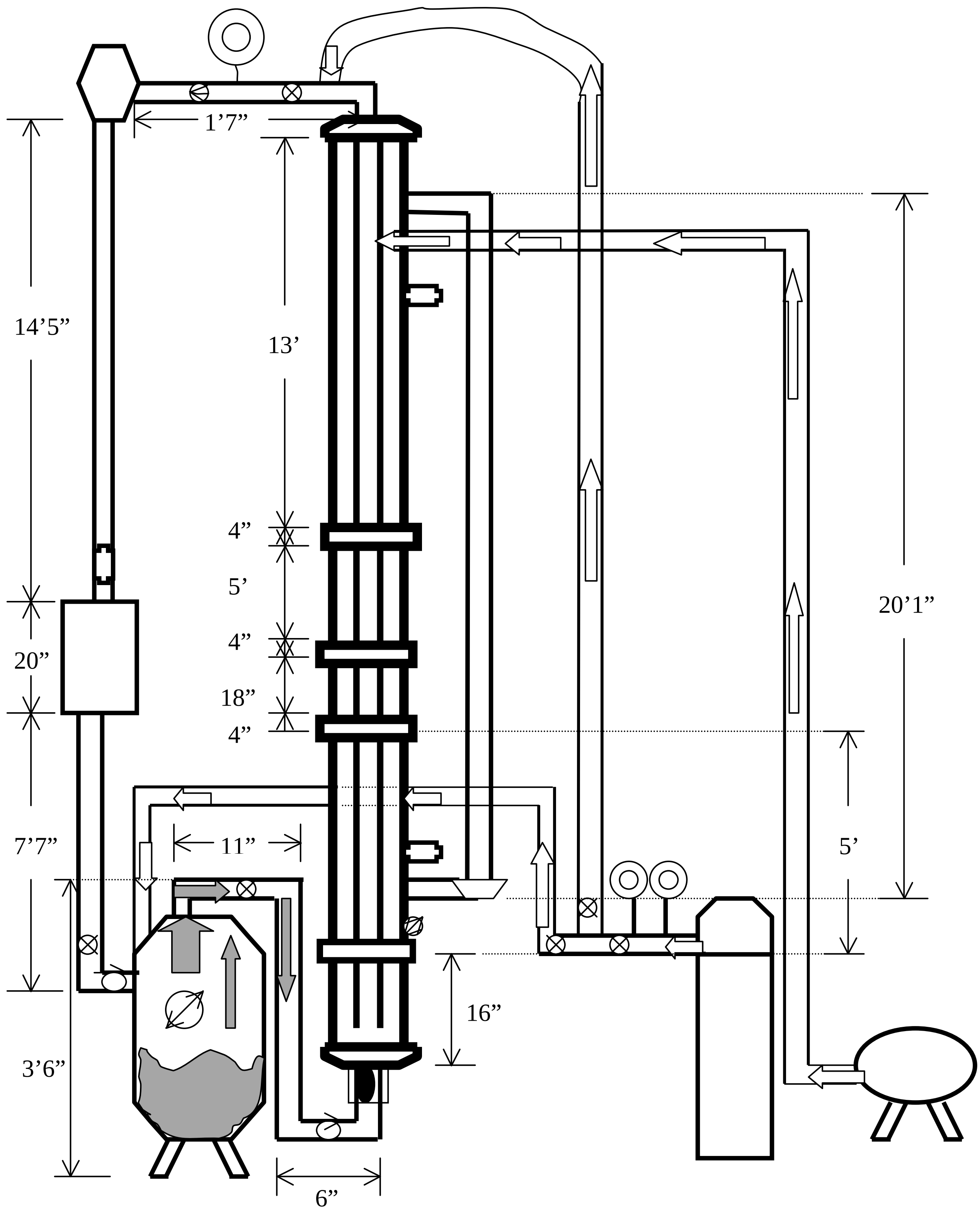

Figure 3.3: Schematic of Experimental Apparatus with Dimensions

To prevent the back-pressure regulator from malfunctioning, it was periodically taken apart and cleaned. This prevented the accumulation of particles within the valve causing it to malfunction during the next experiment. This approach worked well and solved a problem which until solved, was a nuisance.

3.2 Experimental Materials

The liquid compositions used in the experiments were made up of water and oil. The water used was tap water of no specific nature. No salt was added to the water in an attempts to make the water a little denser and more representative of formation waters. For the initial set of test runs, paraffin mineral oil[3] was used as the oil component. This oil had an average specific gravity of 0.845 (at 25^0 C) and an average viscosity of 16.2 (at 40^0 C). This oil was first used to complete a set of tests runs and have results that could be compared to the results of crude oil found in field operations. The liquid compositions used in the experiments ranged from 100% water to 100% mineral oil. The composition was changed by 15% for each new set of test runs. For example, after the set of test runs was completed for 100% mineral oil, the composition was changed to 85% mineral oil and 15% water. This trend was continued until the composition was 100% water. Refer to Table 5.1 for the complete matrix of tests that were completed. This matrix includes the different compositions that were tested as well as the different reservoir and compressor pressures that were used.

After completing the initial set of tests runs, crude oil was used. This crude oil came from an oil field operated in Kentucky by Bretagne Oil and Gas Company. This crude oil had a specific gravity of 0.846. The oil was first filtered using sieving screens to remove any particulate matter that was associated with field production. This was done because the experimental apparatus had dimensions that are smaller than those found in normal production operations. This could have led to failure within the apparatus due to the accumulation of these particles. The test matrix used with the crude oil was the same as that used for the mineral oil tests.

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3. VWR Scientific Products, West Chester, PA

3.3 Experimental Procedure

The objective of the procedure was to determine pressure and temperature measurements in the annulus, and fluid flow rates at the surface for various gas injection pressures. From this information, optimum gas injection pressures could be determined for various reservoir pressures and compositions. The following procedure was used to obtain the data necessary for these determinations:

1. A liquid composition was selected and poured into the tank that represented the production formation. This was accomplished by pouring the liquid composition into the surface barrel and allowing it to gravity feed into the tank.
2. The valve between the surface barrel and the tank was then closed and the tank was pressurized to the specified formation pressure. This was accomplished by using a nitrogen cylinder.
3. The compressor was then started and it pressurized itself to a maximum of 200 psi. The gauge that controlled the exiting pressure from the compressor was then set to the determined pressure. This value ranged from 70 to 85 psi.
4. Two valves were then simultaneously opened. One valve allowed the liquid to flow from the pressurized tank into the bottom of the wellbore, through the standing valve. The other valve allowed gas to flow from the nitrogen tank up to the top of the wellbore and down the annulus. This was done to simulate a head pressure on the liquid as it was entering the wellbore. These two pressures were kept at the same level.
5. Once the pressure and liquid level within the wellbore had reached its maximum value and leveled off, another valve was opened which introduced the compressor air to the top of the wellbore. This compressed air served as the injected gas in a normal gas lift operation.
6. The compressed air flowed down the annulus and forced the formation liquids up the dip tube. Since the compressor pressure was set at a higher value than the back pressure regulator, the regulator was forced open and allowed the fluid to flow through it and down to the surface barrel.

7. Once all of the liquids within the wellbore had been produced, all three valves, which controlled the invasion of liquid formation into the wellbore, the head pressure, and the compressor, were shut off.
8. Pressure readings were taken every half second, during this whole process, from both the top and bottom pressure transducers. These values were recorded.
9. The annulus temperature was recorded for the same length of time. The time and data of these measurements were recorded.
10. The volumetric flow rate of fluids at the surface was also recorded using the flow meter. The time and data of these measurements were recorded.
11. The system was depressurized and steps 4-10 were repeated until the entire volume of liquid within the tank had been depleted.
12. Once the liquid in the tank had been depleted, the reservoir pressure and compressor pressure values were changed and steps 1-11 were repeated until the entire range of pressures had been tested.
13. Once the entire range of pressures had been tested, the reservoir composition was changed and steps 1-12 were repeated for the entire range of reservoir and compressor pressure values.

It was fairly easy to determine the point when all of the liquids had been removed from the wellbore. This point was determined by observing both the differential pressure and flow meter readings. The differential pressure achieved the maximum value just before the compressor air was introduced into the wellbore. As the compressed air U-tubed the liquids from the annulus into the dip tube, the differential pressure continued to drop until it reached the minimum value. This minimum value indicated that there was no more liquid in the annulus. Also, when observing the flow meter, there was an initial surge of flow when the compressor air was introduced. This indicated that the air above the liquid slug was exiting the system through the flow meter. After this, the flow meter readings decreased to a certain value which indicated that the liquid was working its way through the meter. Finally, the flow meter readings shot back up to a high value and stayed constant, indicating that mostly air remained in the system and was exiting through the meter.

Another variable that was measured by the system was the liquid fallback. This variable was observed during the depressurization stage, when the reservoir and compressor pressures had been shut off. As the system depressurized, the differential pressure readings were observed to be increasing from the minimum value obtained when all of the liquid had been removed from the annulus. This indicated that some liquid in the dip tube had not been produced and had fallen back to the bottom of the wellbore. This value varied slightly with the different range of pressures and liquid compositions. Results of this variable can be seen in the graphs which are found in the appendix.

Ambient pressure data were also obtained from the Penn State Meteorology Department Weather Station. The station continuously recorded atmospheric pressure from University Park, PA. Therefore, a corresponding ambient pressure was recorded at the same time each data point was recorded in the laboratory.

It should be noted that barometric pressure data are available in two forms: station pressure and mean sea level (MSL) pressure. Station pressure is the absolute pressure recorded locally at the weather station and the MSL pressure is the local pressure adjusted for mean sea level conditions. MSL pressure is the barometric pressure reported to the public. Station pressure is the pressure that was considered for the ambient conditions of these experiments [Temple (1995)]. For example, when the local absolute pressure is 28.50 inches Hg (965 millibars or 14.0 psia), the barometric pressure at University Park, PA is approximately 29.90 inches Hg (1013.2 millibars or 14.7 psia) [Merritt (1995)].

4.0 ANALYSIS AND DISCUSSION OF RESULTS

4.1 Overview of Data Collection

The purpose of data collection in these experiments was to determine the optimum surface gas injection pressure and volume required for a given reservoir pressure and composition. To achieve this objective, numerous pressure, temperature, and surface flow rates were recorded for each test. Although there were only three different locations used to measure pressure and one to measure flow rates, there were literally thousands of data points recorded during a single test. These data points were then plotted and analyzed. Great effort was made to obtain data that were as accurate as possible. However, due to the apparatus design and the limitations of the instruments, experimental error was unavoidable.

4.2 Limitations of the Backpressure Regulator

The weakest link in the system was the backpressure regulator. The backpressure regulator is located at the top of the wellbore. The main function of this regulator was to hold the designated reservoir pressure and liquid in the wellbore until the injection gas was introduced. At this point, the injected gas would force the liquid through the regulator and into the surface collection barrel. The regulator setting would be somewhere between the reservoir pressure and the injection gas pressure. For example, if the range of reservoir pressures was 45 to 65 psi and the range of injection gas pressures was 70 to 90 psi, then the regulator would be set between 66 and 70 psia. However, the regulator would occasionally collect sediment from the apparatus and would fail to completely close after a test was completed. Consequently, it would fail to retain the reservoir pressure in the wellbore for subsequent tests. This problem was mitigated by removing the regulator and thoroughly cleaning it.

4.3 Summary of Results

In this experimental study, the primary independent variables were reservoir composition, reservoir pressure, artificial wellhead pressure, and injection gas pressure. The primary dependant variables were liquid level within the wellbore, gas volume requirements, surface flow rates, and liquid production. For a specific reservoir composition, a wide range of reservoir pressures, artificial wellhead pressures, and surface compressor pressures were selected. Corresponding liquid levels, surface flow rates and liquid production were recorded. The gas volume requirements can subsequently be calculated using the dimensions of the wellbore and the above mentioned data. Optimum gas volume requirements and surface injection pressures could then be determined for each reservoir composition and pressure.

A summary of experimental parameters, for this study, is shown in Table 5.1. After conducting experimental runs with numerous values for both the reservoir pressures and injection gas pressures, it was determined that it would be best to complete the entire experiment with these ranges. The reasons for this conclusion are as follows:

1. The compressor, which was used for the injection gas, was only capable of injecting up to 140 pounds of pressure.
2. The backpressure regulator was only capable of retaining 175 pounds of pressure.
3. The nitrogen tank, used for pressurizing the reservoir, was only capable of safely injecting 100 pounds of pressure.
4. The tank, used as our reservoir, could only safely hold 100 pounds of pressure.

Once the range of reservoir pressures were determined, a wide range of gas injection pressures were tested and the range of 80 to 95 psi were determined to be the most efficient. The use of pressures less than 80 psi resulted in problems with lifting the reservoir fluids, and the use of pressures greater than 95 psi was inefficient, because the gas would quickly by-pass the fluids. It was observed in this latter case, that less production resulted.

As stated earlier, the entire set of experimental tests has yet to be completed. More specifically, the set of mineral oil tests have been completed, but the crude oil tests are only about 50% completed. However, plots and the analysis of the mineral oil tests have been completed. The only variable yet to be calculated for the mineral oil tests is the overall gas volume requirements for each experiment. In order to do this, we intend to place an instrument over the outlet of the compressor in order to record the velocity of the gas. Once this is accomplished, the gas volume requirements can be calculated using this velocity data along with the pressure of the injected gas and the dimensions of the apparatus. The same procedure will be used for the crude oil tests once they are completed. After the gas volume requirements

Chamberlift Test Matrix

		100% Oil	85% Oil 15% Water	70% Oil 30% Water	55% Oil 45% Water	40% Oil 60% Water	25% Oil 75% Water	10% Oil 90% Water	100% Water
		Reservoir and Head Pressures (same value)							
Com. Pressure (Gas Injection Pressure)	80 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig
		50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig
		55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig
		60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig
		65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig
	85 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig
		50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig
		55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig
		60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig
		65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig
	90 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig
		50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig
		55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig
		60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig
		65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig
	95 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig	45 psig
		50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig	50 psig
		55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig	55 psig
		60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig	60 psig
		65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig	65 psig
		70 psig	70 psig	70 psig	70 psig	70 psig	70 psig	70 psig	70 psig
		75 psig	75 psig	75 psig	75 psig	75 psig	75 psig	75 psig	75 psig
		80 psig	80 psig	80 psig	80 psig	80 psig	80 psig	80 psig	80 psig
		85 psig	85 psig	85 psig	85 psig	85 psig	85 psig	85 psig	85 psig
		90psig	90psig	90psig	90psig	90psig	90psig	90psig	90psig

Table 5.1: Experimental Test Matrix

are calculated for each experiment, the data will be entered into the mathematical model in order to model the fluid flow dynamics. This model has been completed and awaits the entire matrix of experimental data. Upon completion of the modeling, the final results will be applied to actual field tests. These field tests will be conducted by Bretagne Oil and Natural Gas Company in the Big Sinking Spring field, located in Kentucky.

Once the experimental tests using mineral oil were completed, they were graphed and analyzed. Figures 5.1 and 5.2 show the trends of pressure when plotted. It can be seen that these two plots vary greatly. Figure 5.1 shows a test in which there was no breakthrough of gas in the liquid slug. Therefore, this test was more efficient because the time of the injected gas and the liquid fallback was less than that of a test in which there was breakthrough. Also, this type of test resulted in a greater percentage of liquid production at the surface. Figure 5.2 shows a test in which there was breakthrough of gas in the liquid slug. This was less efficient, because it required more gas to produce the liquid slug and the liquid fallback was greater. Hence, there was less overall liquid production at the surface.

The analysis for each test included: determining the liquid level within the wellbore, determining the time of the injected gas, gas lift breakthrough and liquid fallback. Tables A.1 through A.8, in Appendix A, summarize the liquid levels within the wellbore and the time of the injected gas for two tests at each of the determined reservoir and gas injection pressures. It can be seen by analyzing the time of injected gas that some ratios of injected gas pressure to reservoir pressure were more efficient than others. For each table, the highlighted rows are the tests that appear to be the most efficient. It should be noted, however, that the actual gas volume requirements have not yet been calculated for each test, so these results could change. The values for the liquid levels are actual pressure measurements that correspond to a certain height or volume. For example, a liquid level value of 2.0 psi corresponds to an actual volume of approximately 3.0 liters of liquid within the wellbore; and a liquid level value of 2.5 psi corresponds to a volume of approximately 4.0 liters of liquid.

From the analysis of the mineral oil tests, a few important trends have been noticed. As stated in the abstract, most of these trends are consistent with those found in previous literature. Some of these trends include:

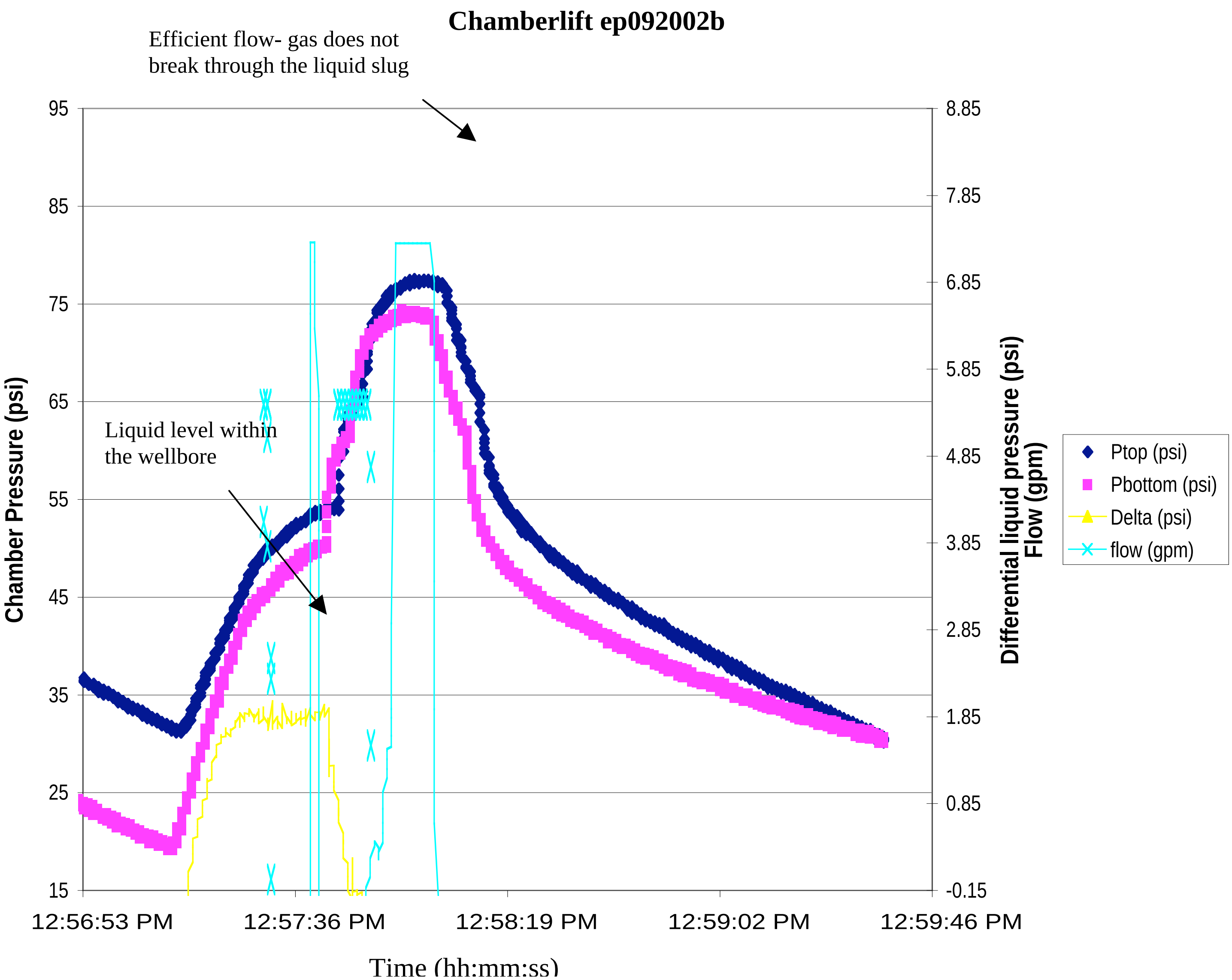

Figure 5.1: Efficient chamberlift test using 70% mineral oil and 30% water.

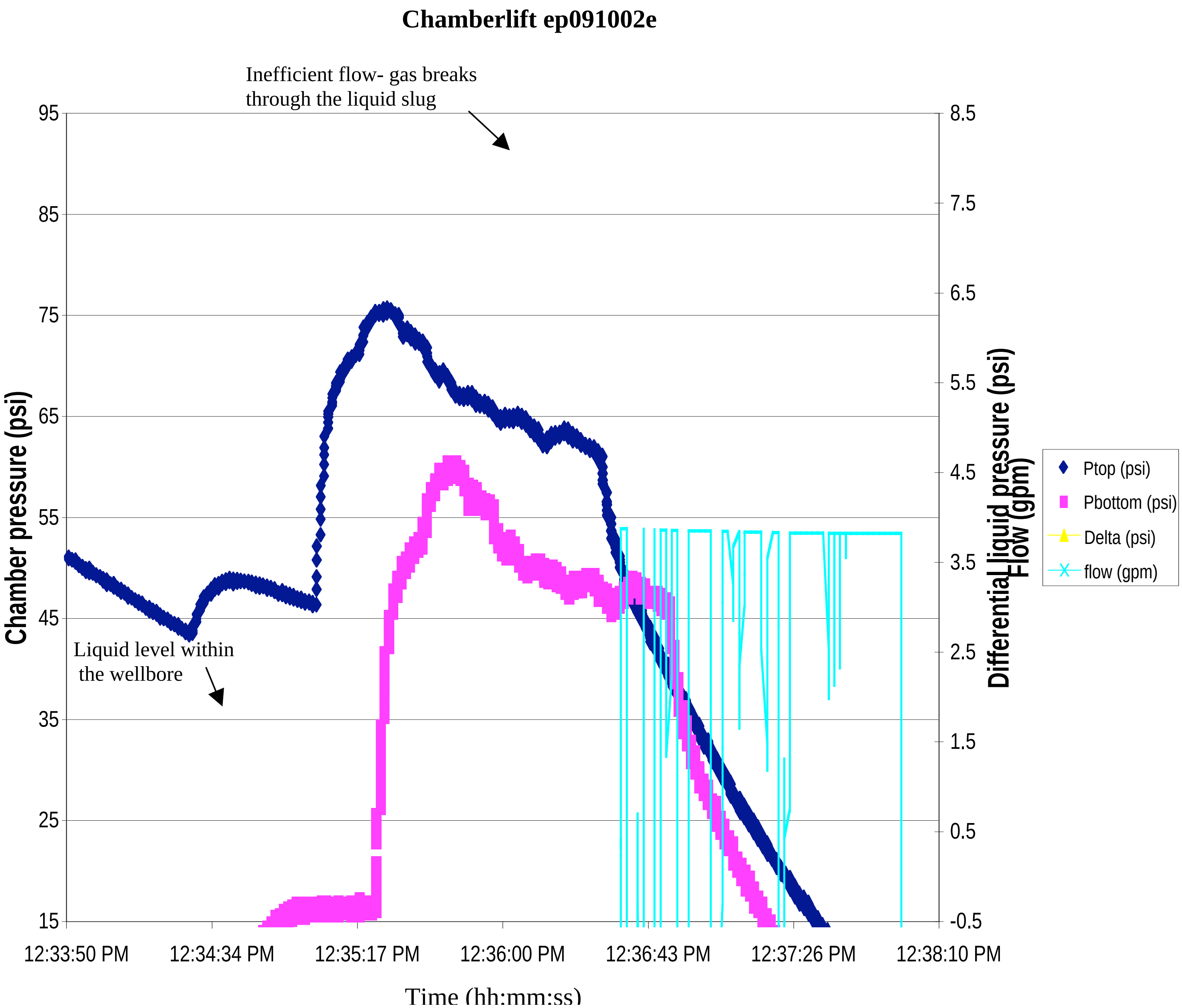

Figure 5.2: Inefficient chamberlift test using 100% mineral oil.

1. There appears to be a small range of efficient ratios between the gas injection pressure and the reservoir pressure. This trend holds true for all reservoir compositions. A ratio that is too small is inefficient, because the gas has difficulty lifting the liquid slug. A ratio that is too large is inefficient because the gas quickly breaks through the liquid slug, causing a large amount of fallback.
2. The height of the liquid column, within the wellbore, has an effect on the overall production and efficiency. Regardless, of the ratios between the pressures, a small liquid column increases the chances of gas breakthrough and less efficient liquid recovery. However, if the liquid column height is excessively large, the lifting of the liquid, by the gas is unattainable, regardless of the pressure ratios. An optimum range of liquid column height for this experimental apparatus was between 7 and 12 feet.
3. The system appears to be less efficient as the percentage of water increases. The exact reason for this observation needs to be further investigated.

In summary, the data generated, thus far, are believed to be accurate and reliable. Also, there are some trends that must be further studied using crude oil, rather than mineral oil, in order to verify the results. When completed, the data should provide a good basis for validating existing and future mathematical models for chamberlift optimization. Also, the information obtained from this research should be useful in designing field scale operations.

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 Summary and Conclusions

The objective of this study is to determine the optimum gas injection pressures and volume requirements for a chamberlift system. This optimization would be done for a wide variety of reservoir pressures and compositions. Once the experimental tests have been completed, the data would be used in a mathematical model to simulate the fluid flow dynamics within the wellbore. Upon completion, these results will be carried out in a field demonstration in order to test their validity.

To date, tests using mineral oil have been completed and tests using crude oil are approximately 50% completed. A mathematical model has been developed and awaits testing using the results of the experimental runs. Thus far, certain trends have been noticed, which are consistent with previously published literature. However, it is believed that the results from this experiment will be more detailed and accurate. The experimental tests should be concluded by the end of April and the results from the mathematical model should be concluded by the middle of June. Further field tests are planned during Phase II.

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APPENDIX A

RESULTS OF MINERAL OIL TESTS

TEST RESULTS							
COMPOSITION: 100% MINERAL OIL							
Test #	Gas Injection Press.	Reservoir Press.	Liquid Level	Gas Injection Time (sec)	Fluid Level	Gas Injection Time (sec)	Comments
0904f	85	55	3.0	32	3.2	33	
0904b	85	45	3.6	38			
0905b	85	60	3.1	29	3.5	37	
0904g	85	65	2.8	31	3.0	28	
0906a	90	60	2.5	114	3.0	142	Breakthru with both peaks
0906b	90	65	2.7	167	3.1	134	Breakthru with both peaks
0906c	90	70	2.8	120	3.2	123	Breakthru with both peaks
0906d	90	75	2.7	101	3.2	122	Breakthru with both peaks
0906e	90	80	3.2	117	3.3	110	Breakthru with both peaks
0909a	90	85	2.3	64	3.2	154	Breakthru with both peaks
0910d	90	90	3.6	128	3.8	144	Breakthru with both peaks
0910e	80	55	2.5	72	3.0	230	Breakthru with both peaks
0910f	80	65	2.8	121	2.9	136	Breakthru with both peaks
0911c	75	55	1.9	110	2.3	135	Breakthru with both peaks
0913a	75	55	2.4	33	2.5	33	Breakthru with both peaks

Table A.1: Liquid levels and gas injection times for tests with 100% mineral oil.

TEST RESULTS							
COMPOSITION: 85% MINERAL OIL, 15% WATER							
Test #	Gas Injection Press.	Reservoir Press.	Liquid Level	Gas Injection Time (sec)	Fluid Level	Gas Injection Time (sec)	Comments
0916g	75	45	2.7	28	3.0	31	
0916h	75	50	2.8	37	3.1	58	
0916i	75	55	2.5	32	2.9	25	
0916j	75	60	2.8	28	3.0	43	
0916k	80	45	2.9	31	3.1	40	
0917b	80	50	2.5	22	2.6	35	
0917c	80	55	2.6	21	3.0	24	
0917d	80	60	2.5	21	3.1	28	
0917e	80	65	2.9	25	3.3	28	
0917f	85	45	2.4	18	2.8	21	
0917g	85	50	2.7	21	3.1	27	
0917h	85	55	2.7	21	3,2	25	
0918a	85	60	3.0	23	3.6	27	
0918b	85	65	3.1	25	3.3	27	
0918c	90	45	2.5	18	3.0	25	
0918d	90	50	2.7	19	2.9	21	
0918e	90	55	2.7	18	2.9	21	
0918f	90	60	2.8	20	3.1	22	
0918g	90	65	2.8	19	3.2	26	
0918h	90	60	2.6	32	3.0	28	
0918i	90	65	2.5	29	3.3	45	
0918j	90	70	3.2	37	3.6	41	
0918k	90	75	2.4	24	3.6	45	
0918L	90	80	2.7	41	3.3	37	
0918m	90	85	2.5	36	3.0	45	
0919a	90	90	3.7	60	4.0	58	Breakthru with both peaks

Table A.2: Liquid levels and gas injection times for tests with 85% mineral oil and 15% water. .

TEST RESULTS							
COMPOSITION: 70% MINERAL OIL, 30% WATER							
Test #	Gas Injection Press.	Reservoir Press.	Liquid Level	Gas Injection Time (sec)	Fluid Level	Gas Injection Time (sec)	Comments
0919j	75	45	2.4	26	2.8	29	
0919k	75	50	2.6	31	3.5	49	
0920a	75	55	2.5	28	2.8	26	
0920b	75	60	2.3	19	3.0	29	
0920d	75	65	3.8	112	4.6	97	
0920e	80	45	3	43	3.4	37	
0923a	80	50	2.6	34	3.1	36	
0923b	80	55	2.5	26	2.8	25	
0923c	80	60	2.9	59	3.4	37	Breakthru with second peak
0923d	80	65	3.5	32	3.8	48	
0923e	85	45	2.6	36	3.4	76	
0923f	85	50	2.9	26	3.6	39	
0923g	85	55	2.7	26	3.5	44	
0923h	85	60	2.7	67	3.2	36	Breakthru with second peak
0923i	85	65	2.9	45	3.2	27	
0923j	90	45	2.7	25	3.2	26	
0924a	90	50	2.6	44	3.9	80	
0924b	90	55	3.1	68	4	57	
0924c	90	60	3	54	3.5	32	
0924d	90	65	3	23	3.4	31	
0924e	90	60	1.6	22	3.5	63	
0924f	90	65	3	89	3.1	37	
0924g	90	70	2.8	26	3.7	63	
0924h	90	75	2.8	31	4.1	64	
0930a	90	80	3.6	32	4.2	45	
0930b	90	85	3.6	84	4.2	73	
0930c	90	90	4.3	32	4.9	34	

Table A.3: Liquid levels and gas injection times for tests with 70% mineral oil and 30% water. .

TEST RESULTS							
COMPOSITION: 55% MINERAL OIL, 45% WATER							
Test #	Gas Injection Pressure	Reservoir Press.	Liquid Level	Gas Injection Time (sec)	Fluid Level	Gas Injection Time (sec)	Comments
0930L	75	45	2.2	22	2.7	23	
0930m	75	50	2.4	27	2.9	27	
0930n	75	55	3.0	37	3.9	36	
0930o	75	60	2.8	40	3.6	26	
0930p	75	65	2.4	24	3.9	28	
0930q	80	45	1.8	18	2.0	18	
0930r	80	50	1.8	19	2.9	24	
0930s	80	55	1.8	18	2.7	22	
1001a	80	60	2.6	32	3.0	25	
1001b	80	65	2.8	25	3.5	29	
1001c	85	45	2.6	20	2.9	20	
1002a	85	50	2.5	21	3.0	25	
1002b	85	55	2.8	34	3.3	27	
1002c	85	60	2.7	26	3.6	29	
1002e	85	65	2.8	24	3.0	24	
1002f	90	45	2.9	25	3.3	27	
1002g	90	50	2.9	21	3.1	29	
1002h	90	55	3.0	25	3.5	26	
1002i	90	60	2.7	22	3.7	36	
1002j	90	65	3.5	35	4.2	35	
1003a	90	60	2.9	32	3.2	35	
1003b	90	65	3.0	33	3.4	48	
1003c	90	70	2.8	60	3.6	39	
1003d	90	75	3.2	30	3.6	31	
1003e	90	80	3.3	28	4.0	31	
1003f	90	85	2.5	45	3.9	40	
1003g	90	90	3.4	34	3.6	33	

Table A.4: Liquid levels and gas injection times for tests with 55% mineral oil and 45% water. .

TEST RESULTS							
COMPOSITION: 40% MINERAL OIL, 60% WATER							
Test #	**Gas Injection Pressure**	**Reservoir Press.**	**Liquid Level**	**Gas Injection Time (sec)**	**Fluid Level**	**Gas Injection Time (sec)**	**Comments**
1004a	75	45	2.3	22	2.5	24	
1004b	75	50	2.4	21	2.8	25	
1004c	75	55	2.7	23	3.0	25	
1007a	75	60	2.6	23	2.9	28	
1007b	75	65	2.8	28	3.5	31	
1007c	80	45	2.5	24	2.7	24	
1007d	80	50	2.4	20	3.6	17	
1007e	80	55	2.8	35	4.0	30	
1008a	80	60	2.9	24	3.3	25	
1008b	80	65	3.1	24	3.3	27	
1008c	85	45	2.2	16	2.3	17	
1008d	85	50	2.4	18	2.7	20	
1008e	85	55	2.6	19	2.8	20	
1009a	85	60	2.9	18	3.0	19	
1009b	85	65	3.2	21	3.6	24	
1009c	90	45	2.4	18	3.7	22	
1009d	90	50	2.7	18	4.0	23	
1009e	90	55	2.7	18	3.0	20	
1009f	90	60	3.0	18	3.4	22	
1009g	90	65	3.1	19	3.3	20	
1014a	90	60	3.0	30	3.5	34	
1014b	90	65	3.5	33	3.8	36	
1014c	90	70	3.3	29	3.6	31	
1014d	90	75	3.6	61	4.4	34	First peak had breakthru
1014e	90	80	4.8	42	5.0	43	
1016a	90	85	3.5	25	3.8	27	
1016b	90	90	3.7	36	4.2	32	

Table A.5: Liquid levels and gas injection times for tests with 40% mineral oil and 60% water. .

TEST RESULTS							
COMPOSITION: 25% MINERAL OIL, 75% WATER							
Test #	Gas Injection Press.	Reservoir Press.	Fluid Level	Gas Injection Time (sec)	Fluid Level	Gas Injection Time (sec)	Comments
1016k	75	45	2.5	23	2.9	25	
1016L	75	50	2.8	23	3.3	26	
1016m	75	55	3.0	24	3.5	27	
1016n	75	60	3.0	23	3.6	26	
1016o	75	65	3.0	26	3.5	28	
1016p	80	45	2.5	21	2.8	22	
1016q	80	50	2.4	19	2.9	20	
1022a	80	55	2.8	18	3.0	22	
1022b	80	60	3.0	22	3.3	23	
1022c	80	65	2.9	23	3.5	24	
1022d	85	45	2.5	20	2.6	18	
1022e	85	50	2.7	20	2.9	21	
1022f	85	55	3.0	22	3.2	21	
1022g	85	60	3.3	21	3.5	20	
1025a	85	65	3.4	19	3.7	26	
1025b	90	45	2.2	17	2.9	19	
1025c	90	50	2.4	17	2.6	16	
1025d	90	55	2.7	18	2.9	20	
1025e	90	60	3.0	18	3.4	19	
1025f	90	65	3.2	18	3.7	19	
1025g	90	60	3.0	24	3.4	26	
1025h	90	65	3.4	26	4.0	30	
1025i	90	70	2.8	22	3.8	27	
1025j	90	75	3.3	24	3.7	26	
1025k	90	80	3.0	23	3.5	26	
1028a	90	85	3.3	26	3.8	29	
1028b	90	90	3.6	27	4.0	30	

Table A.6: Liquid levels and gas injection times for tests with 25% mineral oil and 75% water. .

TEST RESULTS							
COMPOSITION: 10% MINERAL OIL, 90% WATER							
Test #	Gas Injection Press.	Reservoir Press.	Fluid Level	Gas Injection Time (sec)	Fluid Level	Gas Injection Time (sec)	Comments
1029a	75	45	2.4	18	2.7	20	
1029b	75	50	2.5	18	2.8	20	
1029c	75	55	2.7	19	2.9	20	
1029d	75	60	2.5	18	3.0	21	
1029e	75	65	3.0	21	3.5	23	
1030a	80	45	2.5	17	2.8	19	
1030b	80	50	2.6	17	2.8	19	
1030c	80	55	2.5	16	2.9	18	
1030d	80	60	2.5	15	3.1	19	
1030e	80	65	3.0	19	3.4	21	
1030f	85	45	2.9	18	3.6	22	
1030g	85	50	2.6	16	2.9	17	
1030h	85	55	2.6	15	3.0	17	
1030i	85	60	2.7	15	3.0	17	
1030j	85	65	2.6	17	3.0	18	
1031a	90	45	2.6	19	3.9	24	
1031b	90	50	2.5	15	2.7	16	
1031c	90	55	2.7	16	2.9	17	
1031d	90	60	2.0	13	2.1	13	
1031e	90	65	2.0	14	2.2	16	
1031f	90	60	2.5	23	3.3	29	Breakthru with both peaks
1031g	90	65	4.2	38	5.0	53	
1031h	90	70	3.4	29	3.6	32	
1031i	90	75	3.0	25	3.6	27	
1031j	90	80	2.9	23	3.4	24	
1031k	90	85	3.3	24	3.5	25	
1105a	90	90	3.4	29	3.6	32	

Table A.7: Liquid levels and gas injection times for tests with 10% mineral oil and 90% water. .

TEST RESULTS							
COMPOSITION: 0% MINERAL OIL, 100% WATER							
Test #	Gas Injection Press.	Reservoir Press.	Fluid Level	Gas Injection Time (sec)	Fluid Level	Gas Injection Time (sec)	Comments
1111a	75	45	2.6	23	2.8	24	
1111b	75	50	2.7	23	2.9	24	
1111c	75	55	2.6	20	2.9	23	
1111d	75	60	2.9	23	3.1	25	
1111e	75	65	2.8	22	3.5	26	
1111f	80	45	2.6	18	2.7	19	
1111g	80	50	2.6	18	2.8	19	
1111h	80	55	2.7	18	2.9	21	
1112b	80	60	3.2	20	3.5	21	
1112c	80	65	2.9	21	3.5	22	
1112d	85	45	2.3	17	2.7	18	
1112e	85	50	2.8	20	2.9	20	
1112f	85	55	2.8	18	3.0	20	
1112g	85	60	2.8	18	3.2	21	
1112h	85	65	2.9	20	3.5	22	
1112i	90	45	3.0	18	3.5	21	
1112j	90	50	2.8	17	3.4	19	
1112k	90	55	2.9	17	3.0	18	
1112L	90	60	2.9	18	3.5	19	
1112m	90	65	2.9	17	4.1	24	
1112n	90	60	2.5	21	2.9	27	Breakthru with both peaks
1112o	90	65	2.7	24	3.0	28	Breakthru with both peaks
1112p	90	70	2.8	26	3.2	29	Breakthru with second peak
1112q	90	75	3.0	24	3.9	31	
1114a	90	80	2.8	30	3.2	31	Breakthru with both peaks
1114b	90	85	3.1	34	3.8	38	Breakthru with both peaks
1114c	90	90	2.7	34	3.1	36	Breakthru with both peaks

Table A.8: Liquid levels and gas injection times for tests with 100% water. .

Design Development and in Well Testing of a Prototype Tool for in Well Enhancement of Recovery of Natural Gas Via use of a Gas Operated Automatic Lift Pump

during the Period 02/14/2002 to 05/15/2002

By

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DISCLAIMER

Abstract

A 'Gas Operated Automated Lift Pump' has been conceptually developed constructed in prototype and determined to be applicable for use in removing fluids from "stripper wells" thereby increasing production of natural gas. Bench scale and laboratory test of the key tool component, the automated pressure controlled valve assembly, has established the potential applicability of a prototype tool in watered out stripper wells. Tool applicability is targeted to operating conditions of 50 to 600 psi down hole pressure with brine and fluid lift capacity varying from 0.1 to 6.0+ BBL/ tool cycle. In field precursor testing of a pilot predecessor tool of larger dimensions and weight than that targeted for fabrication and deployment as part of the SWC program has shown promising results. A precursor field test of tool [s] have shown improved natural gas production 1.6 X to 2.4X, regular automatic cycling of tool [1 Trip each 1 – 1.5 Day] and auto lifting of brines [0.33 – 1.5Bbl/cycle] from a brine producing natural gas stripper well. Field testing of the above referenced designed prototype tool for this phase of the project showed similar brine production [0.25 to 1 Bbl/ tool run with 1 to 2 day cycles] and frequency of tool cycles during the early period of field trials. Field trials of the new prototype tool evidenced metallurgy problems in materials construction compatibility resulting in premature actuator failure and decreasing frequency of tool runs and lesser quantity of fluids production with each subsequent tool trip. Field and laboratory analysis have diagnosed the problem and designed a remedy for further in field-testing. This premature failure was diagnosed as corrosion on one of the actuator components. The problem occurred as a function of miniaturizing of components to achieve a desired, "well tender friendly" smaller tool configuration. Additional lab trials and in field testing of the smaller prototype tool with a modified more corrosive resistant actuator are scheduled for the 4th calendar quarter of 2002. This work will be conducted by BEDCO as part of its on going commitment to establish working G.O.A.L. Tool technology to assist in the production of gas and oil from the nations aging stripper wells. This work will be supported by the SWC and NYSERDA in a follow on award for field trials of G.O.A.L. PetroPump Tools.

The cost of the G.O.A.L. PetroPump and the attendant well head modifications in comparison to the improvements of gas production achieved by the prototype tools, at current market prices of $3.00 Mcf, suggest a potential payback on capital investment of 1 to 1.5 years.

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INTRODUCTION

The following is the final report under DOE NETL Prime Award No. DE-FC26-00NT41025, Subcontract No.2052-BEDC-DOE-1025 on the development of a prototype tool for the automatic lifting of brines with subsequent improved gas flow production from watered out stripper wells. This feat is accomplished through the use of an on tool automated pressure-sensing/ actuating value that is preset to pass through a predetermined volume of brine with subsequent lifting of that brine to a surface process unit and brine tank. The energy for that lift is powered solely by in well geologic formation pressure.

EXECUTIVE SUMMARY

More than 8% of the US natural gas production is derived from "Stripper Wells" averaging approximately 15-mcf/ day. Much of the United States and the world's natural gas producing wells suffer from declining and restricted production due to the presence and build up of brines in the well bore. Conventional techniques for addressing and or removal of the brine are cumbersome and costly. The scope of this project is to develop an alternative technology [total fluids pump] for the automatic lifting of that brine/ fluid to the surface using in well down hole pressure to activate an in tool valve. This sensing control valve is automatically held open by an internal pressure sensing mechanism allowing the tool to drop into the fluid column in the well. Passage ways through the tool allow passage and accumulation of brine atop the tool to a preset column thickness at which time the on tool pressure sensing mechanism closes the tool valve. This closure is accomplished via the combined hydrostatic pressure of the brine atop the tool and system backpressure. An in well down hole seal of the tool to the casing is accomplished by a set of dual flex cups which surround the tool and make circular contact with the well casing. Subsequently tool and fluid column are lifted to the surface driven by below tool formation pressure [in well below tool pressure].

In the work completed to date on this project BEDCO has confirmed the need for and applicability of an automated tool, which will remove, accumulated fluids [brines] from gas wells and increase gas flow. BEDCO has confirmed these needs and results of increased gas yield post brine removal from wells via meetings, work sessions, well records review, interviews with well field owners and operators and preliminary production response from predecessor tools. These owners and operators currently use sundry methods of brine removal to produce gas from their stripper wells. Interviews with both well owners and operators speak to a common problem in production of natural gas from stripper wells using conventionally available techniques. That problem being, that current production techniques and tools for removal of fluids [Brines] leads to intermittent and often irregular production of gas from stripper wells and certain process unit problems such as winter icing. A need for regular automated fluid removal and more uniform gas production is desired and needed.

BEDCO has produced and bench tested a prototype tool to meet industry needs and simulated in field testing with a 98% adherence/ correlation to the designed tool plan.

BEDCO has further begun to define the numbers and types of wells applicable for such an automated tool through technical work and review sessions evaluating tens to hundreds of "stripper wells' production records with a regional natural gas producer. The number of wells for which the technology is applicable in the Appalachian Region, in the tools current configuration [i.e. sized for 4 to 6 inch ID wells], are numbered in the high thousands. Through out the country, and with further miniaturization of certain tool components the, wells for which the technology is applicable number into the tens of thousands.

The completed work to date on bench tools and prototype tools for field use has focused on tool design and construction of durable materials that are tolerant of down well physical and chemical conditions. To that end materials of construction are Hastelloy, 316 stainless steel for all tool body parts and condensate tolerant synthetics materials for tool sealing cups and BUNA-N materials for automated valve seats. Tooling and machining of components, assembly processes for components and current generation production prototypes are so configured to match with or lend themselves to standard oil and gas field specifications and conditions of service tool [s] availability and technician capability. A field demonstration tool of 32" in length and 42# of total weight has been manufactured and is under ongoing bench testing to determine performance characteristics and simulate in well/ in field-testing. Installation for this new tool design in a chosen Lenape Resources Inc. natural gas well # 52 occurred in March 2002. The well physical characteristics are show in Table 1 - 1 in the Appendix.

It has been determined from predecessor [larger] tool testing that variable tool response is necessary to optimize the performance to low pressure wells and low volume fluid production from certain stripper wells. To address such needs BEDCO has developed bench test apparatus for mock up tool configurations to simulate and address the need for variable stroke and valve seat configuration design to address variable well conditions related to geology conditions and life cycle of the well. Further this apparatus has been and is used to calibrate assembled tools for in field-testing. As noted previous, in field tool testing with prior generation pilot tools has confirmed this need and ability to adjust the tool to wells with lower down hole to well head pressure differentials and lighter brine [fluids] loads. It is also apparent from this testing that smaller pressure sensor control mechanisms would allow for construction of a smaller tool and accommodate a wider selection of candidate wells. Producers express interest for a 2 to 2.5" diameter tool.

Development of real time metrics which will quantify the results of the tool deployment and in well testing as well as provide detailed information for refinement of construction and operation of the tool are critical to the project success. We have determined that the oil and gas industry has begun to address these needs with a limited number of first generation continuous data loggers targeted to collect some of the key pressure and flow data associated with operating wells. BEDCO has further 'in field" deployed and initiated configuration of one such data logger unit on a test well to confirm its use and applicability to the "Prototype Tool".

EXPERIMENTAL

SIMULATION AND ANALYSIS

Analytic modeling was developed to assess candidate fluid lift pump configurations. Analytic simulations indicated that the pressure at which a sensor controlled valve will closed is controlled, to a first order, by the sensor-actuator compression ratio, spring force plus valve and shaft weight, and the initial sensor-actuator charge pressure and charge temperature. Additionally it was concluded analytically, that the pressure at which a sensor-actuator controlled valve will open, once closed, is related, to a first order, only to the ratio of the sensor-actuator cross-sectional area to the valve cross-sectional area, the pressure above the valve, and the pressure below the valve. Based on these understandings, various valve and sensor-actuator geometry were analyzed and alternative configurations and operating strategies were evaluated.

DEVELOPMENT TESTING

A development test program was designed to correlate the analytic modeling and to provide calibrations for development of fluid lift pumps.

The test vehicle consisted of a tubular section containing, and supporting, a sensor-actuator assembly. This was attached to a cylindrical valve seat assemble. A valve shaft was attached to the lower [free] end of the sensor-actuator in such a way that as gas pressure [forces] compressed the sensor-actuator the valve head was pulled up into the valve seat. Upper and lower pressure caps were attached to the cylindrical assembly. Bottled nitrogen plus control valves and gauges completed the test set up. Testing was also conducted with test items immersed at pressure under water. The results indicate no significant difference between water and air [gas] testing.

Tests were initiated with the sensor-actuator-controlled valve in the open position. Gas pressure was increased below the valve, filling and pressurizing the total test vehicle, until the sensor-actuator assembly compressed closing the valve. This simulated the fluid pump descending into the well, being exposed to the flow pressure and hydrostatic fluid pressure, and eventually shutting in the well. The testing established the validity of the analytic modeling of in-well valve closing providing an analytic basis for design modifications.

Each test was continued to simulate the fluid pump arriving at the well head. The pressure above the sensor-actuator-controlled valve was bled off; corresponding to that which would be dissipated into the tank and sales line as the fluid pump approached the surface. The pressure above the sensor-actuator, in the test vehicle, was varied parametrically from one to five atmospheres to assess the validity of the analytical modeling. The pressure below the valve, and sensor-actuator, was reduced until the valve opened. This represented the reduction of well flow pressure that would result as the gas was discharged from below the liquid pump. Once again, the experimental data was in good agreement with analytic predictions of the conditions necessary for valve opening. Analytic modeling was used to evaluate alternative fluid pump designs and operating strategies.

FLUID PUMP CONFIGURATIONS

Two sensor-actuator diameters and several valve head configurations were tested over a range of simulated operating conditions. A liquid pump design was tentatively selected, fabricated and tested. Sensor-actuator compression ratios were varied (stroke adjustments) and sensor-actuator charge pressures were selected parametrically to characterize the liquid pump development model. Figure 1 represents sample results of development testing for the selected configuration (hundreds of test have been conducted with a variety of configurations).

FIGURE 1 Gas **Operated Automatic Liquid Pumping System (fluid pump)**

Bench testing of TOOL #1 with a reduced stroke. August 10, 2001

Summary: Calibration testing of Tool #1 was conducted with a reduced stroke of about 1.05"

Test Results: (Pressure are PSIG) Stroke about 1.05 inches (+\- .02")

Charge Pressure	Valve Closing Pressure	Pressure above Valve At Valve Opening	Opening Pressure	Absolute Pressures Calculations Pcharge	Pclose	Popen	Po/Pc	Pa/Pc
20	58	20	32	34.70	72.70	46.70	0.64	0.48
20	58	0	20	34.70	72.70	34.70	0.48	0.20
20	55	0	18	34.70	69.70	32.70	0.47	0.21
20	56	0	18	34.70	70.70	32.70	0.46	0.21
20	55	30	40	34.70	69.70	54.70	0.78	0.64
20	55	30	40	34.70	69.70	54.70	0.78	0.64
20	57	20	32	34.70	71.70	46.70	0.65	0.48
30	70	30	43	44.70	84.70	57.70	0.68	0.53
30	70	30	44	44.70	84.70	58.70	0.69	0.53
30	73	30	44	44.70	87.70	58.70	0.67	0.51
30	70	50	59	44.70	84.70	73.70	0.87	0.76
30	70	60	65	44.70	84.70	79.70	0.94	0.88
50	106	50	66	64.70	120.70	80.70	0.67	0.54
50	107	30	51	64.70	121.70	65.70	0.54	0.37
50	107	20	42	64.70	121.70	56.70	0.47	0.29

In all testing, the calculated absolute pressure ratios (that is, valve opening pressure/valve closing pressure, and pressure above the valve at opening/valve closing pressure) can be characterized by a straight line plot, the slope being determined by the ratio of the sensor-actuator effective cross-sectional area to the valve seating cross-sectional area.

Specifications have been developed for the fabrication of two alternative sensor-actuator configurations; one with a reduced diameter (1.70" vs. 2"), and both with longer available strokes (20% increase). Discussions are in process with suppliers.

RESULTS AND DISCUSSIONS

The project has been broken down into six major tasks. Those work tasks and the status of activities on those tasks are outlined below:

1.0 COMPLETE DESIGN OF PROTOTYPE TOOL

1.1 The project senior engineering, senior manufacturing and scientific personnel have conducted meetings and work sessions with field engineering/ well operations personnel to outline field durability needs, assembly, adjustment, ease of installation and service specifications for the prototype tools. Findings to date indicate the obvious needs for chemical compatibility with down hole chemistry. This is addressed via the use of Hastelloy, 316 stainless steel metallurgy and valve seat [Buna N] and sealing cup chemistry that will be tolerant of both brine and condensate. Additional findings go to near term application of the tool in 4 inch casing wells and longer term application of tool use in tubing of 2.5 inch or smaller diameter. Immediate needs for the 4 inch cased wells need to address tool total weight, total length, and assembly/ deployment/disassembly of tool components in the field.

1.2 Specific elements that have been addressed are the length, weight and tool diameter to allow for maximum use in varying type of wells and minimum amount of reconfiguration of well head and associated cost. Ancestral tools were in excess of 6 feet in length and 105 pounds in weight. Operating predecessor prototypes for the tool under current design/construction reduced length to 46 inches and weight to ~54 pounds. The tool constructed and bench testing for deployment and testing for the SWC 2002 project is 32" in length and weighs ~ 42 pounds. This design and construction configuration allows ease of deployment of the G.O.A.L. PetroPump and retrieval by a well tender with minimal changes in configuration to a typical well head lubricator.

1.3 Another specific element determined in field meetings for tool modification is the component assembly characteristics. Field assembly, disassembly and adjustment must be possible with the fewest number of field tools and personnel to assist. To that end, tool design and construction has been simplified and addressed to oil and gas industry standards. This includes only three- [3] field serviceable disconnects and these are constructed with standard 6 pitch General Acme threads. Components have been reduced from 27 or more in predecessor tools to 14. Basic material for the tool body is commercially available durable 316 stainless steel. Minimum steps for tool assembly and large milled tool flat areas [wrench flats] complete the simplified design and assembly. This design/ construction/ assembly approach all lends itself to service and maintenance work by standard industry tools [i.e. 36" and 48" pipe wrench, 18" and 24" adjustable wrench and 3# and 5# hammer].

1.4 Field and bench testing has lead to further tool modification of valve seal mechanism improving simulated and field confirmed results with the SWC new designed tool.

1.4 Project senior engineering, manufacturing and scientific personnel have conducted work sessions and have completed a prototype tool in conjunction with the specialized machining firm of Eagle Tool and Die. The tool has completed bench testing and well simulation testing. The, "user friendly", smaller tool was installed in a test wells in March 2002. To achieve the above referenced reduced size and weight of tool, senior engineering designed for the use of a new design and constructed [20 % smaller diameter] self actuating control mechanism for the automated control valve. This major change in design and construction fostered other reductions and size leading to the decreased tool length of ~15" from predecessor tools to the current 32" prototype for SWC in well demonstration and decrease in weight of ~12 pounds to a current weight of ~42 pounds. These represent significant changes, which lend them self to one-man installation and ease of use and retrieval. In process drawings and list of materials stock for machining of components have been simplified in form and reduced in total numbers of components to 14 from 27. The drawings and materials stock list are completed. The documents have been reviewed by the joint team to determine the possibility of further simplification and reduction in component parts. Valve actuator protection against over-pressurization from ambient forces down well was determined as a potential factor in tool operations and design/ construct compensated.

1.5 Project senior engineering in conjunction with the manufacturing director have designed, constructed, modified and refined a bench testing device on which the prototype tool has and was tested prior to and post in field testing. Lab testing of varying pressure [equating to differing in well brine head/ pressure] simulations has been tested to confirm viability and operational integrity of the constructed bench testing equipment and tool critical components. Changes in the actuator stroke and seating area of the self actuating valve assemble have been subject to test to allow for and confirm potential for operation in low pressure and small brine/ fluid load environments.

1.6 Specifications and modifications to the pressure sensing [valve control] device for the operation of the in tool automatic valve have been developed from the above completed meetings, work sessions and test stand work with specific reference to targeted installation wells.

2.0 CONSTRUCT AND BENCH TEST PROTOTYPE TOOL

2.1 The prototype tool was constructed and bench tested against design parameters to which it adhered with greater than 98% correlation. The tool was in lab modified to accommodate learned information from predecessor on going field test to avert over pressurization by ambient forces in down hole conditions. Well operation simulation testing is on going as part of company QA/QC and product evolution.

3.0 SELECT CANDIDATE WELLS

3.1 Meetings and work sessions with Lenape Resources Inc. have been conducted to assemble a list of candidate wells and choose a well for testing of the "Prototype Tool".

3.2 Starting with a list of more than 200 operating and shut in stripper wells a short list of more than 50 wells was assembled. This short list was further refined to 2 target wells. From those two alternative wells, LRI # 52 was chosen for testing.

3.3 Considerations evaluated in choosing LRI # 52 include total yield over time since completion, current yield, and history of fluid production, decline curves and previous testing database.

- As noted above, two alternative test wells were considered. LRI # 52 and LRI #29 were subsequently evaluated for field tool use and evaluation.
- Data on these wells is shown in the appendices
- LRI # 52 had been previously tested with predecessor tools and has the most complete available history of technical data for evaluation and comparison of the many variables associated with gas production which makes it a technical favorite for testing and analysis. The well however is associated with a sales/ gathering system which periodically [especially during low commercial gas demand] that pressures up to in excess of 100 psi versus normal operating pressures of 50 psi making gas production from the well under those conditions onerous.
- Well LRI # 29 as a candidate has less data base and history of close watched operations, but has an advantage of being produced into a sales line with an LRI owned/ operated compressor station which theoretically can minimize wide/ wild swings of back-pressure on the system.

3.5 Associated data on water/ brine production on these wells and other back up candidate wells is continuing to be assembled along with well response [production] information related to intermittent or regular removal of those brines. The final choice of test well was made upon data review and completion of tool assembly with in field-testing initiated in March of 2002 on well # 52.

4.0 TEST WELL PRODUCTION

4.1 Quantification of gas production before, during and post "Prototype Tool' deployment is a key element on the development of metrics to confirm applicability and success of the tool. Current technology on most wells for quantification of gas yield and pressure is performed by analogue instrumentation. This analogue instrumentation is tied to a specific orifice plate size in the well process unit and recorded on a circular 'pie' chart. The charts are subsequently integrated and quantified by third party off site contractors at a later date.

4.2 The project scientist and engineers have assembled some of this analogue data as it relates to the target well for in field-testing and continue to assemble review and interpret this historic data. Production from this well meets targeted test parameters. Those parameters include down hole pressure and historic production challenges which between the period of 1994 to 1999 showing low to no gas production from this well # 52 prior to physical swabbing / brine removal with a work over rig to remove several tens of barrels of brine.

4.3 In field process production data from a larger and heavier predecessor tool is also undergoing analysis and was used in final fabrication of the SWC prototype test tool and wellhead modification parameters. Reduced data to date from this predecessor tools shows an increase gas production from [2] two stripper wells of >1.6X to 2.4X. Regular tool automatic cycles at 1cycle each 1-1.5 days with 0.3 to 0.8 barrels of fluid produced per cycle @ 15 to 20 cycles/ month yielding 8 to 10 barrels/ month of brine are recorded. In well and at well head operating conditions evidence typical pressure ranges expected for the SWC test of 50 to 60 psi backpressure and down hole pressure conditions of 100 to 150 psi.

4.4 Real time comprehensive data collection of well head, process unit and sales line pressure and flow are critical to thorough comprehension of well and tool operation. To that end BEDCO has acquired and deployed a digital recording data logger to capture this type of information. Digital data loggers can collect comprehensive "real time" data at the well head and the process unit. Technical information was first assembled on manufactures and suppliers of continuous recording digital data loggers [well head computers] to collect and log both volume yield and pressure through out the well head and process unit system.

4.5 Bids were solicited for the purchase of a unit most applicable to project needs.

4.6 A successful bidder/ supplier of the well head data logger has been selected. The unit wellhead computer, solar panel and battery] has been purchased installed and field-tested.

4.7 The components of the unit have been field installed on a chosen data collection/ confirmation well in the Lenape Resources System. Unit software and sensors have been installed and calibrated. Results to date show accurate relative correlation with analogue recording charts on the well and the ability to collect and recorded data in digital form on as frequent as 1-minute intervals. Down load of system data via cellular link has been proven viable. Soft ware challenges in manipulating the data for accurate/ absolute correlation/ comparison on a 1 to 1 basis were worked on by BEDCO and the equipment manufacturer to achieve in field data collection/ recording and telephonic down loading success.

4.9 Preliminary field recorded data has been retrieved, downloaded and formatted for correlation with the analogue data from the well. An example of incremental data being recorded is presented in Figure 2. Daily summary data is also available.

Figure 2

HOURLY REPORT
FLOW AUTOMATION CORP.
HOUSTON, TEXAS
DATE: 08/03/01
METER NAME: METER RUN #1 TIME: 05:20:33

CONFIGURATION DATA

Contract Hour	08:00	Spec. Gravity	0.6	Mole % CO2	0.0
Mole % N2	0.0	Energy Content	1000.0	Pipe Diameter	1.987
Orifice Bore	0.375	Tap Config.	Flange	Tap Location	Downstream
Temperature Base	60.0	Pressure Base	14.65	Atmos. Pressure	14.7
Low DP Cut-Off	0.5	Fpv Method	AGA8 Gross	2530 Method	2530-1992
Fwv Method	Manual	Fwv Factor	1.0	Water Content	1.0
Well Stream	Enabled	Well Stream Val.	1.0		

DATE	TIME	VOLUME MSCF	ENERGY MMBTU	AVG SQRT (DP * AP)	AVG. DP IN H20	AVG. P PSIG	AVG. T DEG. F
07/17/01	08:00	0.1699	0.1699	9.18453	1.31	51.6	1.89
07/17/01	08:30	0.1874	0.1874	9.71828	1.47	51.46	1.86
07/17/01	09:00	0.1871	0.1871	9.68400	1.46	51.3	1.84
07/17/01	09:30	0.1874	0.1874	9.68333	1.47	51.02	1.79
07/17/01	10:00	0.2043	0.2043	10.45441	1.73	50.06	1.62
07/17/01	10:30	0.1855	0.1855	9.60922	1.49	49.5	1.51
07/17/01	11:00	0.1714	0.1714	9.05914	1.32	49.46	1.5
07/17/01	11:30	0.1781	0.1781	9.23295	1.36	49.73	1.54
07/17/01	12:00	0.1902	0.1902	9.81453	1.53	50.06	1.59
07/17/01	12:30	0.1855	0.1855	9.48633	1.43	50.07	1.58
07/17/01	13:00	0.1693	0.1693	9.09532	1.32	50.15	1.6
07/17/01	13:30	0.1245	0.1245	8.77455	1.22	50.9	1.73
07/17/01	14:00	0.1014	0.1014	7.63768	0.87	53.57	2.2
07/17/01	14:30	0.2102	0.2102	10.66151	1.69	54.2	2.32

4.8 The "Data Logger" programming is being further addressed to provide more application to project needs.

4.10 Software and formatting components were reviewed and modified to meet project data needs. Additional considerations for future use include transducer outputs and event indicators (surface arrival and departure of the fluid pump) are being considered for incorporation in the status reports.

5.0 EVALUATION OF PERFORMANCE

5.1 Well # 52 tool installation took place in March of 2002 with, testing in March, April, May, June and July of 2002. Gas gathering system pressure back up / increases in sales line backpressure were coincident with tool installation in March of 2002 and made initial tool runs and data interpretation awkward. Sales line compressor shut down [s] and service work effectively "pressured out" the tool from running for the first several weeks of operation and testing. During this period line pressures measured at 65 to 70 psi. Well head shut in pressure for LRI # 52 during this same period measured as low as 85 psi. In general a 12-psi pressure differential between well and sales line is required to operate the tool. Tool runs during this period were sporadic and variable in terms of fluid production and post tool run gas production. Fluids production with tool runs varied from 0 [zero] to 0.33 Bbls per run. Gas production for the period varied from a high of 14. 7 mcf/d to a low of 7 mcf/d. At the maximum value the gas production and fluid production were similar to the predecessor BEDCO tool and much higher [>60%] than the standard casing plunger used in this well in 2000 and previous years. At the low production of 7 mcf/d the tool and well were producing on average 1 mcf/d less than the average production achieved by the standard casing plunger. All yields were greater than production historically achieved using tubing alone.

5.2 Observations of prototype tool runs, brine production and gas production from well # 52 during this period of unusually unstable line pressures over several months indicated a general decline in fluid production and decrease in gas production post each tool run. In all two different tools [the second tool at BEDCO cost and expense, as it was not budgeted for in the SWC work plan] were subject to in well/ in field-testing. Both evidenced a similar pattern of performance in well # 52. As such, this portion of the test was reluctantly terminated in early August of 2002 and the tools were returned to BEDCO facility for preliminary evaluation. Physical observations of the prototype tool valve assembly indicated a misalignment of the valve and valve seat. This misalignment appeared to stem from the size reduction efforts, which removed certain valve stem guides. This misalignment alone did not preclude tool operations when bench tested both pre and post well installation and operations. The second more profound discovery of ex-situ well, in laboratory, testing was the appearance of slow pressure loss from the actuator assembly. This pressure loss was observed to occur over a period of hours to days on the tools used and retrieved from well # 52. As the actuator is a sealed system, the immediate source of the leakage/ failure was not readily apparent. The actuators were returned to the manufacturer for destructive analysis testing. Upon arrival at the manufacturer, the actuators were first re-subjected to a water bath pressure test to confirm absence of integrity as found in the BEDCO facility. Confirmation of pressure leakage from the assembly was made. The actuators were subsequently disassembled and examined under high magnification. This examination revealed corrosion holes in the actuator. The location of the corrosion holes were located on the stainless steel side of a Hastelloy- stainless weld line. Both tool actuators showed a similar failure pattern. Research into the problem shows an elevated corrosion index potential between Hastelloy and stainless steel metals. This corrosive potential in the construction of the actuator was compounded by the welding of the stainless steel to the Hastelloy and certain physical restrictions in the fluid passage through the actuator which caused brine [15 – 20 % NaCl] to accumulate adjacent to the welds where the corrosion effects were concentrated.

5.3 Tool design modifications have been made. These modifications include a support mechanism for the valve and valve seat assembly, which will improve alignment and increase concentricity of valve and seat in the tool. This should further reduce potential for seating problems or leakage of the valve once closed and sealed. The more important remedy is a metallurgy change in the contact area [reduce corrosive index potential] between the stainless steel end fitting and the Hastelloy actuator. This metallurgy change has been coupled with a physical modification to the actuator which eliminates blind passages in the tool, which can trap brine and there by concentrate their corrosive effects. BEDCO has self-funded these design modifications and manufacturing of new actuators outside of the SWC sponsorship on the project. Delivery of the new actuators, lab and field-testing are targeted for November 2002.

5.4 Post the determination of the prototype [smaller tool] actuator under performance in August of 2002, BEDCO re-installed a predecessor larger tool in well # 52 to confirm applicability of the technology. This earlier version, larger, somewhat more cumbersome, tool was deployed in late August of 2002. The tool was set with an increased actuator pressure to accommodate accumulated brine not removed during the previous testing. The tool target was to retrieve 0.75+ Bbl of brine on each tool run. Observations during the month of September 2002 showed 5 to 7 tool runs per week yielding 0.75 to 1.0 Bbl of brine per trip. Gas yield after each of the trips has averaged 17.5 mcf/d. The brine production is ~ 2 fold greater than during previous tool test and gas yields ~ 15 to 20% greater. Comments by the well tender post the old tool re-deployment were, "gee that well just gets better and better". Similar results were achieved during the first 3 weeks of October 2002.

5.5 Qualitative evaluation and limited comparison of conventional brine removal techniques commonly deployed in similar wells to the chosen test well is given below as a compilation of information in an anecdotal format developed from interviews with well operators.

Existing methods for brine removal in area Medina Fm. wells more commonly include:

[Note: These methods are common to other Geologic Fm. and wells]

- Periodic swabbing with a "work over" rig to remove accumulated brines and temporarily restore gas flow, requiring a normal two man complement, appropriate swabbing tools, equipment and investment of several hours total time for a 3000 to 4000' well.
- Installation of casing swabs that operate by dropping of the mechanical operated casing swab to a preset stand. When the tool strikes the stand it mechanically closes a valve regardless of the height of column of fluid atop the tool and regardless of the pressure below the tool to lift fluid column and tool weight to the surface. These types of tools normally require manual release and often man assisted recovery.
- Installation of smaller diameter tubing in 4 to 6 inch wells [commonly 1.5 to 2.5" internal diameter tubing] targeted to allow older production gas wells with declining volume and reducing pressure to lift accumulating fluid from the well to the surface via capillary action in the smaller tubing. This technical approach is often employed with the periodic shut in of the well to increase down hole pressure to a level sufficiently high that upon reopening of the well will purge the tubing of the brine/ fluid column. This method also often employs the use of surfactants "soap sticks" to disperse the brine into a foam and "lighten" the fluid column for purging to the surface, the process unit and the brine tank.

- Tubing rabbits are another technology deployed to produce gas from these types of stripper wells via the periodic purging of fluids from the tubing column. The rabbits are in general a smaller version of the mechanical swab tools with similar associated challenges of mechanical and man-assisted operation.

All these above technology assisted improvements for fluid removal have a common need for manpower assistance and or some add on well external pressure or electronic activated semi-automated controller. Dropping and retrieval of tools [casing swabs and rabbits] involve the need for periodic service [release and retrieval] by a well tender, down time on the well production and or some external assistance such as mechanical or electric timers for dropping of tools. Periodic swabbing by a work over rig is the most labor intensive and least cost effective of all methods. Tubing and soaping to lift fluids similarly results in well production down time during periods of well shut in to build pressure to purge the well and also require appropriate manpower.

Interviews with well tenders and operators alike when questioned, what dictates the frequency of servicing a well where one or the other of the above technology is deployed? Most record a common refrain, "When there is sufficient time to get to it [the well]". As such production is highly dependent upon the frequency of service by the operator and punctuated by periods of non-production and spike production.

One such interview on frequency of service and method of operation with a well tender of more than 30 years experience focused on his experience with the most comparable [albeit not operationally comparable to the design and preliminary operational results of the G.O.A.L. PetroPump] technologies of casing swabs/ mechanical swabs/ 'dumb swabs. Questions posed to operator were simply when and how do you decide to deploy or "Drop" a mechanical swab tool and what do you do if problems arise with it cycling/ returning to the surface with brine:

- The candid response was, as a conscientious operator he tries to inspect the well every two days and make a qualitative determination of well production and wellhead pressure. At such time as he determines from his inspection and interpretation of the process unit analogue volume/ flow production chart, pressure reading at the process unit and possibly a well head pressure reading that production and pressure are not acceptable [i.e. gas flow volume down and pressure down based upon qualitative assessment], the mechanical swab tool is physically released from the catcher to the well.
- The well is then next inspected one or two days in the future. The inferred reasoning on this lapse in time frame is that the tender has previous empirical experience indicating that is the approximate time it takes for the tool to make a 'run' [i.e. return to the surface with fluid] in that the mechanical tool must drop completely through the accumulated fluid column to the well stand to set the tool/ close the mechanical valve before it can initiate a run. This presupposes that the fluid column is sufficiently short and the behind mechanical tool pressure sufficiently great to lift both mechanical tool and column of fluid to the surface for processing.
- If/ when the mechanical swab tool does not return to the surface the base interpretation and common empirical experience indicates that this is due to the fact that the pressure behind the tool is insufficient to lift tool and fluid column atop the tool.

- Follow up actions to retrieve a stalled mechanical swab tool can vary and usually evolve from the simplest response of "shutting in" the well to build down hole pressure for 0.5 to 1.0 day [s] with subsequent release of the pressure rapidly directly to the brine tank. More involved and evolved actions can include the addition of a surfactant, shut in of well to build pressure and subsequent purge to brine tank to the more complex action of tool retrieval techniques using other mechanical equipment and tools.
- This non regular purging of the well of the fluids and often long periods of low to no gas flow resultant from stalled mechanical swab tools is referenced to periodically lead to down stream effects such as winter icing of the process unit further reducing gas output from the well.
- The well tenders' summary of operation of wells with mechanical casing swabs is that it tends to produce gas from the well in an uneven and punctuated manner. There are further frequent periods of well down time leading to less overall gas production than the well is capable of were the brine uniformly and regularly removed.

5.3 Project Schedule

Task Performed	[2001] Months [2002] [06/01]-07-08-09-10-11-12-[01/02]-04-06-08-10
Design Tool	>>>>>>>xxxxx C
Construct Prototype	>>>>>>xxxxxxxxxxxxxx C
Select Candidate Well [test]	>>>>>xxxxxxxxxxxxxxxxxC
Bench Test Tool	>----------xxxxxxxxxC
Test Well Production	>>>>>>>>>xxxxxxxxxxxxC
Evaluation of Performance	>>>>>>>>>>>xxxxxxC
Evaluate/ Estimate/ Recommend	>>>>xxxxxxC

Key:
>>>> -Original scheduled time frame
xxxx -Revised time frame to complete
C -Completed task

6.0 EVALUATE ECONOMICS

6.1 Potential economic payback from the use of the GOAL PetroPump is estimated below from results of predecessor tool production increases in the LRI # 52 well. This data used in the base calculations was derived from operations in 2001 and early 2002. As noted above in section 5.4, redeployment of the predecessor tool in well # 52 has improved production in the month of September and October 2002 to an average of 17.5 mcf/d. As such all values noted below for payback and increases of production could be projected to improve by 15 to 20%.

6.2 Estimates of Payback from Production

Assumptions: * "Tool" Cost and Well Modifications @ $8950.00
* LRI # 52 Monthly Average Production with Tubing @ 98 mcf
* LRI # 52 Monthly Average Production with 'casing plunger' @ 252 mcf
- Value of gas @ $3.00 mcf

Table 6-2

Ave. Prod. using GOAL Pump	Ave. Prod. using tubing in 1995	Average Prod. Using 'casing plunger'	Payback @ $3 mcf vs tubing production	Payback @ $3 mcf vs 'casing plunger production
381 mcf [5 mo.]	98 mcf	252 mcf	~10 months	~25 months

Note: Average production for September and October of 2002 for this well using the GOAL PetroPump were averaging 17.5mcf/d or ~ 500 mcf/ month

It must be noted that the yields of the well tested is very small [~3 mcf/day of gas via tubing at initiation of test] in comparison to the average gas stripper well in the US @ 15 mcf/ day. These wells, even with the improvements yielded by the G.O.A.L Petropump are at or below the average US gas stripper well production. Application of the Tool in wells with greater production potential [i.e. the average stripper well] which have need for regular automatic brine [fluids] removal should yield better results and quicker payback on capital invested in the tool. The current cost of the Tool at approximately $9000 complete with wellhead modifications for installation is elevated. This is due to proprietary construction materials and techniques. Production of Tool in a commercial manner should reduce cost and payback on capital investment for the Tool user. Finally the uniqueness of the G.O.A.L PetroPump and its on Tool self-actuating controls to regulated frequency and volume of fluid removal from wells differs greatly from casing plungers producing superior results in these test and has its own unique market niche.

6.3 Cost Comparisons to Other Alternatives

Cost comparison of the G.O.A.L. PetroPump to the common used equipment for fluid removal from gas wells in the depth range of 3000' to 6000' would include:

- Pump Jack/ Beam Lift, associated sucker rod, tubing and down hole pump can have capital cost in the range of $10,000 - $40,000. Operating cost for pump jacks range from $2000 to $10,000/ year depending on volume and type of fluids produced, maintenance, replacement parts and service required.

- Tubing string production could have $8,500 to $15,000 capital cost dependant on tubing diameter and operating cost ranging in the $1500- $3000/ year for manpower & surfactants.

- **Casing plungers' capital cost with the necessary well head modifications to receive the unit are in the range of $3500 to $5000 capital. Additional capital cost for well head controllers for any attempt at automation of casing plungers is also needed [as opposed to man assisted runs], at $1000 to $5000. Operating cost would include manpower at a minimum of $500 to $1000/ year to $2000- $3000/ year on manual run tools. Work over cost to retrieve drowned and or stuck tools are not herein quantified but typical rig/ day cost are $750- $1000.**

- **Tubing plungers [Rabbits] base requirements include the installation of a tubing string at $8,500 to $15,000 as noted above plus the capital cost of a Tubing plunger at $2000 without any automation to $6000 with automation [semi] controls. Operating cost are not dissimilar to casing plungers noted above at $1000 to $3000.**

Further with respect to casing plungers and tubing plungers, they do not operate in the same or similar fashion to the G.O.A.L. PetroPump with on Tool controls and down hole/ up hole smart Tool technology.

In terms of applicability of this G.O.A.L. Tool to wells in the test area of New York State. It was determined that approximately 3,523 gas wells and approximately 529 active oil wells exist in Chatauqua County, New York. Based upon our exposure to the wells in the area it is likely that 50% or more of these wells will have fluid production related problems in the life of the wells. It is further likely they will require some form of tool related technology to produce gas and or oil. Assuming the G.O.A.L. PetroPump Tool would serve 1/3 of the wells in need of tools for enhanced production some 500 to 600 wells would be candidates for the GOAL tool in Chatauqua County. Projecting those numbers to the entire state of New York production could mean more than 1500 tools for state of New York wells.
Assuming only an 8-mcf/d increase per well [in range of test increases] at $3/ mcf could yield $13,000,000 in gas value and a pay back on 1500 tools at $9000/ tool in a one year time period

6.1 Over the recent years several organizations have begun to evaluate the number of stripper gas and oil wells in the United States which exist and are troubled by water production. BEDCO's preliminary review of the number of wells for which the technology being developed may be applicable is derived from several sources. Those specifically referenced here in are:

- **National Survey – Marginal Oil and Gas Report by IOGCC [Annual]**
- **Ohio and West Virginia Survey – University of Kentucky by E. Choong**
- **New York – IOGANY Marginal Well Study sponsored by NYSERDA 2000**

6.3 Details of these survey and more specific analysis will be developed and presented in the final report post in field testing of the tool. A GRI study by Spears indicates > 200,000 stripper wells in North America producing < 25 barrels of fluid/ day. Our preliminary analysis conservatively estimates applicability for the technology too more than 50,000 water producing gas stripper wells in the US. Potential applicability for application to stripper oil wells should be evaluated by separate analysis and testing, however a very conservative estimate could be made at 40,000 oil stripper wells.

CONCLUSION

The need for and applicability of a Gas Operated Automated Lift PetroPump [A Smart Swab Tool] for removal of fluids from stripper wells remains a sound goal and desirable tool for the oil and gas wells of America and the world. Key elements of such a tool are abilities to work in varying geologic environments of pressure, depth, fluid production, in well chemistry and operating conditions. Current target wells require the tool to be readily deployable and serviceable in 4" ID wells with but minor structural changes to the well head and process units to be economically viable.

Future needs of such a Gas Operated Automated [lift] Tool will target wells with 2.5" diameter tubing and or open hole/ large diameter completion wells or open hole completions that are readily retrofit with isolation packers and continuous smaller diameter tubing than the nominal open hole diameter of 6.25".

Bench and test stand testing of varying automated valve closure assemblies and engineering calculations indicate potential operating ranges for the prototype tool at 50 to 600+ [psi] and potential fluid lift of 0.1 to 6_-+ bbl's per tool cycle. Field trials of a prototype tool have confirmed the ability to operate in the lower half of these bench-tested values.

Automated computerized well head data loggers show they can record varying location pressures at the well head and process unit as well as continuous volume of production have evolved to a point to be applicable for in field continuous recording of operating conditions of the prototype tool. This data can serve to act as basis of tool adjustment for optimum performance and to target tool components for upgrade and improvement.

Field trials of this data logger technology on a typical target well have shown both promise of results, need for modification of software formatting and beneficial results of such modifications. These results to date indicate their applicability to meet the needs of quantifying 'real time' the effectiveness and operation of such an automated gas lift tool.

Review of operations records of a regional gas producer [i.e. total yield, current yield and decline curves] in conjunction with precursor [non GOAL PetroPump] tool testing have identified a number wells which can benefit in terms of production increases from use of an automated fluid removal tool. On a national basis tens of thousands of stripper wells appear applicable for use of the technology to improve production. Production increases even if half of the predecessor and prototype tool results can amount to tens of millions of dollars worth of additional recovered energy resources at modest well head re-configuration and G.O.A.L. PetroPump cost which could be recovered with in 1 to 3 years based upon recent prototype tool test results. Tool modifications and improvements can make the tool more durable and better functioning to further increase performance and shorten pay back on capital tool investment.

Appendix 1

Table 1 - 1 Tested Well # 52

Test Period	1996/1997	2001/2002
Completion date	11-1-83	11-1-83
Formation	Medina [Grimsby/ Whirlpool]	Medina [Grimsby/ Whirlpool]
Geology	Sandstone [tight]	Sandstone [tight]
Total Depth	3,343 feet	3,343 feet
Perforations	3,127 – 3,229 feet	3,127 – 3,229 feet
Casing size	4.5"	4.5"
Production prior to test	3 mcf/d via tubing	8mcf/d w/ casing plngr. tool
Well head pressure	320 c/ 60 t psig	180 psig
Line pressure [sales]	60 psig	55 psig
Bottom Hole Temperature	97 deg. F	-----

Table 1 – 2 Candidate Test Well # 29

Test Period	2002
Completion Date	1982
Formation	Medina [Grimsby/ Whirlpool]
Geology	Sandstone [tight]
Total Depth	2390
Perforations	2299 – 2370
Casing size	4.5"
Production prior to test	~9 mcfd w/ std. casing plunger tool
Well head pressure	150 psi
Line pressure [sales]	Variable 25 to 45 psi
Bottom Hole temperature	?

Appendix 2

Attachment C in Original Proposal with Noted Modifications to Reflect Actual Expenditures by BEDCO

	Requested & Received from SWC	Proposed Cost Share by BEDCO	Expended Cost Share by BEDCO
Salaries and Wages	$16,790--	$35,143--	$155.518--
Fringe Benefits	--	--	--
Materials and Supplies	$4,700--	--	--
Equipment	$14,600--	--	--
Travel	$4,220--	$2,170--	$2170--
Publication/ Information Dissemination	--	$2,500--	$2,500--
Other direct Cost [Misc.	--	$3,250--	$3,250--
Prototype tools/ spares and modifications	$12,500-	--	--
Work over Rid/ Fitters	$5,990--	--	--
Facilities and Administration	$1,200--	$5,760--	$5,760--
Totals	$60,000-	$47,653— [44.5%]	$155,518— [73.6%]

Note: Total combined expenditures by SWC and BEDCO on the project are $215,518.00

Identification of Effective Fluid Removal Technologies for Stripper Wells

during the Period 05/15/2002 to 11/30/2002

By

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Disclaimer

Abstract

Prior research for the Department of Energy identified the largest problem contributing to abnormal production decline in stripper gas wells was fluid accumulation in the wellbore. This study developed methodologies including decision trees and a procedure guide to economically identify the most effective fluid removal technology for specific stripper gas well characteristics. The application of systematic methodologies and techniques increases the efficiency of problem assessment and implementation of fluid removal solutions for stripper wells. Effective fluid removal from stripper wells benefits all producers by increasing production and ultimate recoveries since it corrects the most common production decline problem.

The fluid accumulation problem indicates many operators fail to recognize and evaluate the economics of the proper application of fluid removal methods over the entire life cycle of the stripper well. It is critical that changes in fluid removal techniques be effective over the life of the well. due to the limited net income from stripper wells. Therefore, the goal of this research program was to develop an application guide detailing cost effective fluid removal method evaluation and selection procedures.

Current study results indicate little work has been completed regarding fluid removal method selection for wells classified as stripper gas wells, that is, 60 mcfd or less. Further, the national stripper well average is only 15 mcfd while the Appalachian Basin well average is 11 mcfd with either representing a significantly lower volume than that established as stripper well production. To compound the limited production problem, stripper wells are also associated with multiple owners, aging production equipment, and mature, low permeability, low-pressure reservoirs.

The 448 well study group fluid removal method distribution was 289 tubing plungers, 115 pumping units, 26 casing plungers, and 18 swab wells. To complete the study, an existing well database was complemented through detailed wellfile review with producing well characteristics including historic fluid removal mechanisms, completion tubulars, producing and shut-in pressures, production cycles, and volumes per production cycle. In addition, a 40-year semi-log plot of historic monthly production versus time was reviewed for each well, analyzed for fluid removal method production performance, and then assigned a classification of “Good”, “Fair”, or “Poor”.

The study identified 194 fluid removal method changes in 125 of 448 wells. The study found that tubing plunger wells with GLR’s greater than 50 experience significantly better production performance than those with lower GLR’s, while wells on pump are successful across all GLR’s. Casing plunger wells are generally successful in high GLR limited completion interval wells, while successful swab wells have very high GLR’s with very limited fluid production. Ultimately, the study resulted in a step-by-step methodology incorporated into a procedure guide to evaluate and select appropriate fluid removal methods for stripper gas wells.

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Introduction

This study was specifically developed for stripper well operators in a cost-sharing venture between James Engineering, Inc., the Stripper Well Consortium, the National Energy Technology Laboratory, and the New York State Energy Research and Development Authority.

The goal of this research program was to develop a procedure guide to identify cost-effective fluid removal technologies for stripper gas wells.

A study group of 448 wells provided the data to analyze the fluid removal technologies commonly utilized for stripper gas wells including tubing plungers, casing plungers, pumping units, and swabbing. An analysis of the fluid removal methods and their relative efficiencies indicated that wells produced with tubing plungers were 85% successful when the gas liquid ratio, GLR, was 50 mcf per barrel or greater. Data collection forms and decision trees were developed to review stripper gas wells, identify cost-effective fluid removal technologies, and suggest corrective action. The decision trees and data collection forms developed as a result of this research were incorporated into a procedure guide to provide operators with a methodology to evaluate and select appropriate fluid removal methods for stripper gas wells using commonly available data. The systematic methodologies and techniques developed increase the efficiency of problem well assessment and implementation of solutions for stripper gas wells.

This final technical report includes the procedure guide developed as a result of the study and summarizes the results of the specific steps for this study as follows:

- Perform a literature search of the appropriate application of fluid removal technologies for stripper wells
- Develop data collection forms
- Perform a field review of critical parameters affecting maximum flowrate
    - Reservoir pressure
    - Bottom hole flowing pressure
    - Line pressure
    - Gas production rates
    - Fluid production rates
    - Artificial lift mechanism
- Summarize the results of the field review of critical parameters
- Develop a decision tree to select the appropriate fluid removal technology
- Test the decision tree
- Prepare an application guide detailing cost effective fluid removal technologies
- Prepare technical paper and transfer the technology

Executive Summary

This study was specifically developed for stripper well operators in a cost-sharing venture between James Engineering, Inc., the Stripper Well Consortium, the National Energy Technology Laboratory, and the New York State Energy Research and Development Authority.

Prior research performed for the Department of Energy identified the largest problem contributing to abnormal production decline in stripper gas wells was due to fluid accumulation in the wellbore. This study was to develop methodologies including decision trees and procedure guides to economically identify the most effective fluid removal technology for specific stripper well characteristics. The application of systematic methodologies and techniques increases the efficiency of problem assessment and implementation of fluid removal solutions for stripper wells. Effective fluid removal from stripper wells benefits every producer by increasing production and ultimate recoveries since it is the most common production decline problem.

The liquid loading problem indicates that many operators fail to recognize and evaluate the economics of the proper application of fluid removal methods over the entire life cycle of the stripper well. Due to the limited net income from stripper wells, it is critical that changes in fluid removal techniques be effective over the life of the well. Therefore, it was the goal of this research program is to develop and deliver an application guide detailing cost effective fluid removal application selection procedures.

Based upon a 448 well review of critical pressure and production parameters, this study concluded the following:

- Most stripper wells require the application of a fluid removal method to maintain production.
- To optimize production, it is critical that the proper fluid removal method is systematically applied and the operating principals thoroughly understood.
- Further, optimized production to economic depletion is generally achieved when the flowing bottom hole pressure is kept reduced by a consistent removal of fluid.
- The fluid removal methods appropriate to produce stripper gas wells to economic depletion are tubing plungers, casing plungers, pumping units, and swabbing.
- Tubing plungers perform better on wells with high GLR’s, greater than 50, and low fluid volumes, with few depth or completion restrictions.
- Casing plungers perform better on wells with high GLR’s, limited perforation intervals, good mechanical integrity casing, and low fluid production.
- Pumping units are applicable to wells across a broad range of GLR’s, long perforation intervals, and can sustain a lower flowing bottom hole pressure.
- Swabbing is applicable to wells with high GLR’s, large pocket for fluid accumulation, and nominal fluid producing wells.

The procedure guide developed as a result of this study provides stripper well operators a methodology to select the most appropriate fluid removal method for stripper gas wells.

Experimental Apparatus and Operating Data

Operating data supplemented a preexisting well database from an extensive review of wellfiles, operating reports, and field data mainly from wells located in Ohio and New York.

Results and Discussion

This final technical report discusses a statement of the problem, and then summarizes the results of the following steps for this study:

- Perform a literature search of the appropriate application of fluid removal technologies for stripper wells
- Develop data collection forms
- Perform a field review of critical parameters affecting maximum flowrate
    - Reservoir pressure
    - Bottom hole flowing pressure
    - Line pressure
    - Gas production rate
    - Fluid production rate
    - Fluid removal method
- Summarize the results of the field review of critical parameters
- Develop a decision tree to select the appropriate fluid removal technology
- Test the decision tree
- Prepare an application guide detailing cost effective fluid removal technologies
- Prepare a technical paper and transfer the technology

I. A Statement of the Problem

Prior research for the Department of Energy found that 270 of 376 wells evaluated (>70%) exhibited some form of abnormal production decline during the past five years. Nearly 50% of the abnormal production declines were due to liquid loading resulting in decreased reserves and revenue. The frequency of the liquid loading problems represent a significant opportunity for improvement since in many cases liquid loading is a correctable problem through the evaluation and application of appropriate fluid removal technologies to stripper gas wells.

The liquid loading problem indicates that many operators fail to recognize and evaluate the economics of the proper application of fluid removal methods over the entire life cycle of the stripper well. Like hydraulic fracturing, developed to accelerate recovery from low permeability reservoirs, the proper application of fluid removal technologies to low-volume stripper wells should accelerate recovery of reserves. The misapplication of fluid removal methods appears related to temporary solutions for long-term problems.

The source of fluids that cause liquid loading problems are typically free liquids produced with the gas or condensed liquids in the gas, while other sources include inadequate cement bond, fracing or acidizing into water, poor perforation placement, and casing or packer leaks. However, high volumes of produced fluids are not typically associated with stripper gas wells.

The problems associated with stripper gas wells include mature (twenty years old or older), low permeability, low pressure reservoirs, owned by multiple operators, corroded surface facilities, with operators literally stripping the last 10 to 20% of wells' economic ultimate reserves. In addition, while stripper wells are defined as wells with production less than or equal to 60 mcfd or 10 bopd, the national average for stripper well production is only 15 mcfd and 2 bopd. The average Appalachian Basin stripper well only produces 11 mcfd and 0.4 bopd but represents 205,000 of the nation's 646,000 stripper wells. Therefore, by definition, even when stripper well production is maximized, the amount of capital available for repairs or enhancements is limited. Therefore, an absolute necessity in correcting problems with stripper wells is finding an economic solution and it is critical that the changes made in fluid removal techniques be effective for the life of the well.

The procedure guide developed as a result of this research provides methods for evaluating and selecting fluid removal methods for optimum fluid removal from stripper gas wells. A more detailed discussion on the statement of the problem is presented within the text of the procedure guide.

II. Literature Search of Appropriate Application of Fluid Removal Technologies for Stripper Wells

As per the original proposal:
"Search for previous studies and field results to incorporate all pertinent fluid removal technologies and research on the subject."

Data Reduction and Methodology
One hundred sixty-seven references were identified as pertinent to the research on fluid removal technologies for stripper wells and are included in this final report for future reference (Appendix 1). The searches were conducted on the SPE website, the Internet, the Marietta College Library, and the South West Petroleum Short Course 3-CD database. Key search words included liquid loading, artificial lift, fluid removal, gas well performance, and fluid production. Literature pertained to tubing plungers (34%), well performance (27%), general information (14%), pumping units (9%), foamers (5%), casing plungers (3%), progressive cavity pumps (3%), and swabbing (0%).

The literature review confirmed that little research has been completed for wells with production volumes classified as stripper wells and generally focused on the importance of well production performance as a function of the GLR, producing volumes and pressures, and fluid removal efficiency. The review further confirmed that sustained reductions of the flowing bottom hole pressure typically result in sustained production increases. Overall, the results of the literature search proved helpful throughout the study as references of previous work completed on fluid removal methods.

III. Develop Data Collection Forms

As per the original proposal:
"Develop data collection forms of pertinent information to analyze problem wells. Shut-in and producing pressuring information will be gathered to analyze bottom hole producing pressures. Fluid levels and other information will be collected to determine the effects of fluid on bottom hole pressure. Fluid production histories will be confirmed to determine the effect of gas to liquid ratios have on stripper well performance. Well equipment will be analyzed for mechanical failure."

Data Reduction and Methodology
Data collection forms were developed to provide a systematic methodology of gathering data for the analysis of the critical factors that affect the optimum performance of various fluid removal technologies. Experience indicates that through pressure and production decline curve analysis, an operator can typically estimate the productive potential of the producing reservoir and the efficiency of the production method. Ultimately, knowing the productive potential of the reservoir assists the operator in evaluating and selecting the proper fluid removal method.

Data collection forms were developed for the most common fluid removal methods; tubing plungers, casing plungers, beam pumps, and swabbing (Procedure Guide Appendices 3 – 6). While all the data collection forms were similar in design, specific data applicable to each fluid removal method was identified. Sections I, II, and III are for completion by field personnel, while sections IV, V, VI, VII, and VIII are for completion by the production manager. Stripper well operators rely heavily on well tenders to maintain optimum production and therefore completion of Sections I-III can often cue a well tender towards the proper corrective action without any additional action by the production manager required.

Field personnel Section I requests basic well information including producing formation, flowing tubing and casing pressures, domestic gas usage, and specific production cycle data. Section II requests current daily production rates and associated GLR, while Section III requests any comments the well tender might have regarding current operations or recommendations for production improvement.

Production manager Section IV requests analytical data including perforated intervals, casing and tubing sizes and depths, gas sales line size and length, and flowing and shut-in pressures. Section V requests a production performance estimate, Section VI forecasted rates of production, Section VII a description of recent well work, and Section VIII comments and recommendation based upon the analysis.

The data collection forms were utilized throughout the study to analyze fluid removal method performance and were included in the procedure guide with complete instructions to utilize the forms.

IV. Field Review of Critical Factors Affecting Maximum Flow Rate

As per the original proposal:
"James Engineering, Inc. has access to more than 500 stripper wells in Ohio and West Virginia. These wells are of various depths with a wide variety of producing mechanisms. Specific data will be collected and tests run to determine the critical factors affecting the optimum performance of various fluid removal technologies and the effectiveness in maximizing production. The critical factors to be evaluated will include but not be limited to reservoir pressure, bottom hole flowing pressure, line pressure, fluid production rates, gas production rates, artificial lift mechanisms, and surface production equipment."

Data Reduction and Methodology
Previous work for the DOE provided a database of information including lease name and well number, well identification number, well tender, API number, county, township, section, producing status, producing formation, operator, well type, well depth, and completion date. Supplemental information from company capital expenditure reports, detailed wellfile review, orifice chart integration reports, weekly well tender reports, current well tender information, production decline curve analysis, and cumulative production data were incorporated into the database.

From an initial database of 654 wells, a 448 well study group was established after wells that had been sold, plugged, shut-in, classified non-stripper, or outside operated were eliminated. The wells were then grouped according to their fluid removal method as tubing plungers (289, 65%), pumping wells (115, 25%), casing plungers (26, 6%), or swab wells (18, 4%).

Three hundred forty-seven capital expenditures from 1997 – 2001 were summarized by year, lease, well identification number, total cost, and description. Expenditures were further categorized as related to compression, fluid removal method, maintenance, mechanical, miscellaneous, pipeline, purchase, plug and abandon, re-completion, or unknown. Eighty-one (23%) expenditures related to fluid removal method were incorporated into the database.

An extensive wellfile research of all 448 wells identified fluid removal method changes, shut-in pressures, tubing and casing depths, perforation intervals, well tests, and any physical changes that impacted the performance of the fluid removal method. Physical changes included casing repairs, top tubing joint replacement, wellhead and pipeline repairs, well re-completions, and swabbing results. Orifice gas sales charts, chart integration statements, and weekly well tender sheets were reviewed to further identify production cycles, pressures, and well tender comments. All data was summarized and then entered into the database.

Current monthly and cumulative historic production volumes including oil, gas, and water volumes based upon state and in-house data were incorporated into the database and then the GLR's calculated based upon the current and historic volumes.

Historic monthly production decline curves were reviewed and compared to a type decline curve to provide a qualitative assessment of the current production method performance resulting in a classification of “Good”, “Fair”, or “Poor”. The results of this review were then incorporated into the database.

Finally, summary sheets containing database performance information for each well were supplied to respective well tenders requesting current information or corrections including additional shut-in pressure information, beginning and ending cycle pressure, production cycle lengths, field gas and fluid volumes, and sales line pressures. Responses supplied by the well tenders were then incorporated into the database.

The resulting database of critical factors and general well information were analyzed to determine factors affecting the optimum performance of fluid removal technologies and the effectiveness in maximizing production as described in the next section.

V. Summarize Results of Field Review of Critical Parameters

As per the original proposal:
“The results of the field review study will be summarized and analyzed to determine the effects of the critical factors. An attempt will be made to determine when a particular method of fluid removal or artificial lift technology is both appropriate and cost-effective. We will also attempt to bracket at what pressures and fluid rates a particular method of fluid removal fails.”

Data Reduction and Methodology
Database analysis revealed 194 fluid production method changes for 127 wells (28%) with some wells undergoing up to four fluid removal method changes. Further analysis indicated that 394 of the 448 wells (88%) were placed on tubing plunger wells at inception while 37 (8%) were placed on pump. The high percentage of wells on tubing plunger and pump at inception indicate that operators understood a fluid removal method would be required to maintain optimum production.

The following tables present some of the correlations regarding the factors affecting the performance of the fluid removal methods.

Table No. 1 shows the relative performance of each production method based upon historical production decline curve analysis. There was a general even percentage distribution of well performance (“Good”, “Fair”, and “Poor”) for pumping wells and swab wells. However, tubing plungers did have a higher percentage of wells classified as “Good” while casing plungers had a higher percentage of wells performing “Poor”.

Table No. 1				
Production Decline Curve Analysis to Determine Relative Well Performance				
		No. Of Wells (%)		
Production Method	**No. Wells**	**"Good"**	**"Fair"**	**"Poor"**
Tubing Plunger	289	121 (41)	97 (34)	71 (25)
Pumping Unit	115	43 (37)	40 (35)	32 (28)
Casing Plunger	26	7 (27)	7 (27)	12 (46)
Swab Well	18	5 (32)	7 (36)	6 (32)
Total Wells	**448**	**176 (40)**	**151 (34)**	**121 (27)**

Table No. 2 shows the distribution of each method based upon the historic GLR with the ranges of distribution selected arbitrarily. The distribution indicates a major distribution of high GLR wells associated with tubing plungers while pumping units showed a higher distribution in low GLR wells. Casing plungers and swab wells were almost exclusively high GLR wells.

Table No. 2					
GLR Analysis based upon Historic GLR, Mcf/bbl					
		No. Of Wells (%) by GLR			
Production Method	**No. Wells**	**<10**	**10 – 20**	**20 - 50**	**>50**
Tubing Plunger	289	10 (3)	12 (4)	46 (16)	221 (76)
Pumping Unit	115	39 (34)	21 (18)	29 (25)	26 (22)
Casing Plunger	26	0	0	3 (11)	23 (89)
Swab Well	18	0	0	1 (5)	18 (95)
Total Wells	**448**	**49 (11)**	**33 (7)**	**79 (18)**	**288 (64)**

Table No. 3 shows that 85% of the tubing plunger wells classified as "Good" also had GLR greater than 50 mcf per barrel. Also significant was that the casing plunger wells and the swab wells were also greater than 50 mcf per barrel.

Table No. 3					
GLR Analysis based upon Historic GLR, Mcf/bbl Group 1 or "Good" Wells					
		No. Of Wells (%) by GLR			
Production Method	**No. Wells**	**<10**	**10 – 20**	**20 - 50**	**>50**
Tubing Plunger	121 / 289	1 (0)	5 (4)	12 (11)	103 (85)
Pumping Unit	43 / 115	10 (23)	7 (16)	11 (25)	15 (35)
Casing Plunger	7 / 26	0	0	0	7 (100)
Swab Well	5 / 18	0	0	0	5 (100)
Total Wells	**176 / 448**	**11 (6)**	**12 (7)**	**23 (13)**	**130 (74)**

Table No. 4 provides average well characteristics for each of the four fluid removal methods. No meaningful cycle data was available for casing plunger wells. Limited swabbing information did not provide sufficient information for statistical analysis.

Table No. 4							
Average Study Group Production Characteristics							
Production Method	**No. Wells**	**Depth Feet**	**Cycles per Month**	**MCF per Month**	**Bbl per Month**	**Bbl per Cycle**	**Sales Line Psi**
Tubing Plunger	289	5,505	134	332	4.5	0.06	62
Pumping Unit	115	5,058	27	256	24.0	1.40	55
Casing Plunger	26	4,763	-	244	-	-	55
Swab Well	18	4,925	-	378	-	-	45
Total or Average	**448**	**5,062**	**-**	**303**	**-**	**-**	**54**

Table 5 provides a brief summary of the general guidelines for fluid removal method application including GLR, minimum flowing bottom hole pressure, ability to produce maximum fluid, good casing required, investment capital required (“1” = high, “4” = low), and operator training required.

Table No. 5								
Stripper Gas Well Fluid Removal Method Application Guide								
Production Method	**High GLR**	**Low GLR**	**Min. Fbhp**	**Extensive Completion Interval**	**Bbls per Cycle**	**Good Prod Casing**	**Investment Capital $**	**Operator Training**
Tubing Plunger	√			√	0.25 – 1.0		2	√
Pumping Unit	√	√	√	√	1.0 – 5.0		1	√
Casing Plunger	√				0.5 – 3.0	√	3	√
Swab Well	√		√	√	As swabbed		4	

The results of this analysis indicate that tubing plunger wells with GLR’s greater than 50 typically perform better than wells with lower GLR’s. Wells produced by pumping unit were effective regardless of GLR. Wells produced by casing plunger or swabbing, even with high GLR, were not effectively produced. Tubing plungers, casing plungers, and swab wells typically made less fluid monthly than pumping units that averaged significantly higher volumes. Note that the average well only produces 300 mcf per month (10 mcf per day). Final conclusions of the study are provided in the section titled “Conclusion”.

VI. Develop Decision Trees to Select Appropriate Fluid Removal Technologies

As per the original proposal:
"Develop decision trees to identify the problems causing the fluid accumulation and select the most appropriate solution. The decision tree will utilize pressure and rate information gathered on the data collection forms to direct the operator to the most effective fluid removal system."

Data Reduction and Methodology
The Decision Tree Form (Appendix 3) is a four-phase process to aid in fluid removal method analysis and selection. The decision tree provides a methodology to evaluate the most common fluid removal methods for stripper gas wells by dividing the analysis into four separate sections: Phase 1 - Identify the Problem, Phase 2 - Measure the Problem, Phase 3 - Solve the Problem, and Phase 4 – Monitor the Changes and Production.

The Decision Tree Form was designed to address the more common problems faced by operators first, then complete additional analysis by going forward to the next phase as required. This methodology can result in solving the fluid removal evaluation prior to any substantial investment. A Data Collection Form and the Alternate Fluid Removal Method Decision Form are incorporated into the Decision Tree Form. Complete descriptions on using all forms are included in the procedure guide.

VII. Test the Decision Tree

As per the original proposal:
"Run several wells with liquid loading problems through the process to be sure consistent results are achieved."

Data Reduction and Methodology
The decision tree methodology was applied to ten wells where recent well work had been performed to correct liquid loading problems to ensure that consistent results could be achieved. The decision tree form, appropriate data collection form, and alternate fluid removal decision form were completed for each well in the ten well test group. In general, the process for evaluating wells experiencing liquid loading problems utilizing the three forms proved effective. The testing not only refined the decision tree process but the decision tree and data collection forms as well.

The summary provides key indicators regarding the application of the fluid production method, including previous and current fluid removal method, completion date, cumulative gas and total fluids to date, historic GLR, Estimated net cost of fluid removal method change, estimated incremental stabilized production after fluid removal method change, and any specific comments regarding the analysis.

Table No. 6									
Decision Tree Test Result Summary									
Lease	**Previous Fluid Removal Method**	**Current Fluid Removal Method**	**Comp. Date**	**Cumulative Mcf**	**Cumulative Bbls**	**Historic GLR**	**Est. Net Cost**	**Prod. After Change, Mcfm**	**Comment**
Aron Woodford #1	TPL	PJEM	11/14/74	155,530	1,280	120	$10,000	+100	Higher initial prod. predicted
OD Baker #1	SWB	TPL	07/01/77	178,930	510	3,500	$10,000	+200	Initially TPL. Swabbing not effective
John Bird #2	TPL	PJGE	08/20/73	97200	1,215	80	$10,000	+ 200	Significant fluid production - Combined production with #1
L. Derry #3	TPL	SWB	10/24/86	45,190	215	210	$0	+100	Combined production with #1
W. Fitzgerald #1	TPL	CPL	02/03/77	199,950	1,395	145	$5,000	+250	Recent 2002 conversion to CPL
Wm. Garris #2	SWB	TPL	09/01/85	50,970	55	930	$8,500	+0	Tubing test well, Initially TPL Combined production with #1
Hughes Stiles #1	TPL	PJEM	11/30/73	324,090	1,275	255	$10,000	+150	Higher initial prod. predicted
A. Larrick #2	CPL	PJGE	06/04/80	55,040	1,195	45	$10,000	+200	Incomplete prod. history: Offset well experienced better results.
Leachman #1	TPL	CPL	01/27/74	30,610	70	440	$0	+130	Incomplete production history
Ellis Miller #1	SWB	TPL	02/01/94	83,990	995	85	$8,500	+200	Initially TPL

Not all information requested in the data collection forms was available for analysis. A lack of information is consistent for stripper wells due to multiple owners and marginal economics. Particularly, flowing bottom hole pressures, shut-in pressures, and historic total monthly fluid volumes were generally unavailable. Therefore, some estimates may be required to provide a reasonable measure of potential production increases associated with a fluid removal method application.

Most stripper well operators have a good understanding of the day to day operating conditions for their wells, often being the well tender. Therefore, many of the questions or responses requested on the evaluation forms will be known without any wellfile research required. However, the questions and responses requested in the three forms were prepared to be as comprehensive as possible. The overall format of the forms provides a logical and useful tool for the evaluation and selection of fluid removal methods for stripper wells.

VIII. Prepare Application Guide Detailing Cost-Effective Fluid Removal Technologies

As per the original proposal:
"An application guide will be prepared to assist operators in determining appropriate fluid removal methods by evaluating the current producing characteristics of specific wells to maximize recovery of the remaining reserves."

Data Reduction and Methodology
The results of the study were incorporated into a procedure guide to assist operators in evaluating and selecting common fluid removal methods for stripper gas wells, which include tubing plungers, casing plungers, pumping units, and swabbing.

The procedure guide begins with an introduction and overall methodology to utilizing the guide followed by a complete description of the decision tree form. The guide then includes a description of the operation of each fluid removal method providing a typical application range based upon depth, GLR, and fluid production. The guide includes general operational guidelines for installation, the evaluation forms required, the advantages and disadvantages of each method, the identification of potential failure paths, and a listing of diagnostic tools.

IX. Prepare Technical Paper and Transfer the Technology

As per the original proposal:
"The summary report will be presented at either a PTTC conference and or through a SPE technical paper presented at a regional meeting. Additional presentations may be arranged as requested."

An SPE technical paper was presented in Lexington, Kentucky at the 2002 Eastern Regional Meeting. Two Stripper Well Consortium sessions were made in November 2002 in Oklahoma City and Pittsburgh. A presentation was also made to the Penn State petroleum engineering graduate students in November 2002. Additional presentations will be made locally as requested, possibly to the PTTC and the spring Marietta College SPE student chapter meeting, Marietta, Ohio.

The final report and procedure guide will be posted on the SWC website and provided to NYSERDA

X. Conclusion

- Most stripper gas wells require some application of a fluid removal method to maintain optimum production.
- It is important to production optimization that operating principals are thoroughly understood and proper fluid removal methods are systematically applied.
- Stripper well operators rely heavily upon field personnel to maintain optimum production that requires training in fluid removal methods and operating information understanding (location and pipeline maps, production decline curves, and wellbore schematics).
- Stripper well operators must provide well tenders the support and proper tools for production evaluation (Echometers or pressure recorders).
- Optimized production to economic depletion is achieved when the flowing bottom hole pressure is minimizes generally through the consistent removal of fluid.
- The fluid removal methods available to produce stripper gas wells to economic depletion are tubing plungers, casing plungers, pumping units, and swabbing.
- Tubing plungers perform better on wells with high GLR's, greater than 50, and low fluid volumes, with few depth or completion restrictions.
- Casing plungers perform better on wells with high GLR's, limited perforation intervals, good mechanical integrity casing, and low fluid production.
- Pumping units are applicable to wells across a broad range of GLR's, long perforation intervals, and can sustain a lower flowing bottom hole pressure than other methods.
- Swabbing is applicable to wells with very high GLR's, ideally a large pocket below the perforated interval for fluid accumulation, and limited fluid production.
- Additional work in the area of fluid removal method application could further the goal of production optimization.

References:

Appendix 1

Bibliography:

Turner, R.G. Hubbard, M.G., and Duckler, A.E.: "Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells", Journal of Petroleum Technology, November, 1969

Hacksma, J.D., Shell Oil Company: "Users Guide to Predicting Plunger Lift Performance"

List of Acronyms and Abbreviations:

Not Applicable.

Appendix

1 Literature Search Results Summary
2 Procedure Guide

Appendix 1 – page 1
Literature Search Summary and References

Title	Author(s)	Source
1. Analyzing Well Performance XV	McCoy, Podio, Huddleston	SPE
2. Application of Nodal Analysis in Appalachian Gas Wells	Frear, Yu, Blair	SPE 17061
3. Inflow Performance Relationships for Solution Gas Drive Wells	Vogel	SPE 1476
4. Optimum Plunger Lift Operation	Baruzzi, Alhanati	SPE 29455
5. Plungerlift Benefits Bottom Line for a SE NM Operator	Schneider, Mackey	SPE 59705
6. Using Foaming Agents to Remove Liquids from Gas Wells	Dunning, Eakin, Walker	US Mn. 11
7. Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells	Turner, RG	JPT Nov 1969
8. A New Look at Predicting Gas Well Load Up	Coleman, SB	JPT Mar 1999
9. Gas Well Operation with Liquid Production	Lea, Tighe	SPE 11583
10. Introduction to Plunger Lift: Applications, Advantages, Limitations	Beauregard, Ferguson	SWPSC
11. Will Plunger Lift Work in My Well?	Beauregard, Ferguson	SWPSC
12. How to Optimize Production from Plunger Lift Systems I & II	Phillips, Listiak	
13. Plunger Lift Comes of Age	Christian, Lea, Bishop	World Oil 95
14. Predicting Plunger Lift Performance	Hacksma	Shell Oil
15. Plunger Lift Application in Wells with Set Packers or Permanent Tubing	Darden	SPE
16. Dynamic Analysis of Plunger Lift Operations	Lea, J.F.	
17. Defining the Characteristics and Performance of Gas Lift Plungers	Mower, Lea, Beauregard	SPE 14344
18. Design Optimization of Plunger Lift Systems	Avery, Evans	SPE 17585
19. Elimination of Liquid Loading in Low Productivity Gas Wells	Neves, Brimhall	SPE 18833
20. New and Unusual Applications for Plunger Lift System	Beauregard, Morrow	SPE 18868
21. Case Histories: Plunger Lift Boosts Production in Deep Appalachian Wells	Schwall	SPE 18870
22. Optimizing Plunger Lift Operations in Oil and Gas Wells	Wiggins, Nguyen, Gasbarri	SPE 52119
23. Modeling Plunger Lift for Water Removal From Tight Gas Wells	Maggard, Wattenbarger, Scott	SPE 59747

Appendix 1 –page 2
Literature Search Summary and References

Title	Author(s)	Source
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Appendix 2
Procedure Guide

Identification of Effective Fluid Removal Technologies For Stripper Wells

Stripper Well Consortium
Subcontract No. 2042-JE-DOE-1025

Procedure Guide

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I. Introduction

This study was specifically developed for stripper well operators in a cost-sharing venture between James Engineering, Inc., the Stripper Well Consortium, the National Energy Technology Laboratory, the New York State Energy Research and Development Authority. The goal of this research was to develop a procedure guide detailing cost effective fluid removal method selection procedures for stripper gas wells.

SPE paper number 78707 and the final technical report for this research contain a complete description of the methodologies, results, and conclusions realized while developing this procedure guide.

Previous work completed by James Engineering, Inc. found that 270 of 376 wells evaluated (>70%) exhibited some form of abnormal production decline during the past five years. Nearly 50% of the abnormal production declines were due to liquid loading resulting in decreased reserves and revenue. The frequency of liquid loading problems represents a significant opportunity for improvement since in many cases liquid loading is a correctable problem through the systematic evaluation and application of appropriate fluid removal technologies to stripper gas wells.

Wellbore fluids that cause liquid loading problems are typically due to free liquids produced with the gas or condensed liquids in the gas. Additional sources of liquids may be attributable to inadequate cement bond, fracing or acidizing into water, poor perforation placement, or casing or packer leaks. However, high volumes of produced fluids are not typically associated with stripper gas wells.

The current study found that 125 (28%) of the 448 wells evaluated experienced at least one fluid removal method change during its production history. Of these 125 wells, 32 wells experienced multiple fluid removal changes for a total of 194 changes while 75 wells (60%) were ultimately put on pump as a fluid removal method. The multiple changes of fluid removal methods represent additional cost that reduce the already marginal economics of stripper gas well operations.

Stripper gas wells typically have poor reservoir quality and low reservoir pressure that compound the production problems resulting in operators literally stripping the last 10 to 20% of wells economic ultimate reserves. These wells are generally twenty years or older with multiple owners, and bring along with them a broad range of problems.

Experience indicates that twenty percent of the wells often represent a large portion of income producing assets. Therefore, stripper well operators need to able to identify and focus on those wells where a possible change in fluid removal method will make the greatest impact. Ultimately, stripper well operators must identify fluid removal methods that will not only carry a well to ultimate depletion but also where the additional capital cost can be recovered.

An absolute necessity in correcting problems with stripper wells is finding an economic solution. Stripper wells are defined as wells with production less than or equal to 60 mcfd or 10 bopd. However, the national average for stripper well production is 15 mcfd and 2 bopd or 30 mcfdeq (Appendix 1). The Appalachian Basin represents 205,000 of the nation's 646,000 stripper wells, but the average stripper well in the Appalachian Basin only produces 11 mcfd and 0.4 bopd or 14 mcfdeq. By definition, even when stripper well production is maximized, the amount of capital available for repairs or enhancements is limited. It is critical then that changes made in fluid removal techniques be effective for the life of the well. This procedure guide provides methods for evaluating and selecting fluid removal methods for optimum fluid removal from stripper gas wells.

When discussing options for fluid removal, it is recognized that stripper oil wells are typically on pump and only require efficient run times to optimize production. Conversely, most dry gas wells, those with no associated liquids, are only concerned with the minimum pressure afforded through compression. Stripper oil wells and dry gas wells do not lend themselves to fluid removal method selection but only how to optimize the flowing bottom hole pressure. Therefore, the options for fluid removal and specifically the timing of applications are normally associated with stripper gas wells. It is important for the stripper gas well operator to identify those areas where there are opportunities for economic production enhancement through the proper selection of fluid removal methods.

Upon initial completion a gas well generally has sufficient gas velocity to transport all fluids to the surface, while many oil wells require some form of fluid removal. As the gas flow rate and velocity decreases due to decreased reservoir pressure, the fluid suspended in the gas phase begins to drop out and accumulate at the bottom of the well. The well may then begin to slug fluid to the surface, until the fluid column pressure overcomes the reservoir pressure restricting or ceasing production altogether. Stripper gas wells are much more susceptible to this problem.

Liquid loading problems are identified at the surface by erratic gas and/or liquid production volumes, high differential pressure between the casing and the tubing, or additional swabbing or blow downs to maintain production. Erratic gas production is evidenced on gas production orifice meter charts, weekly readings from positive displacement meters, or monthly-integrated gas volume reports. Erratic liquid production is often noticed in weekly reported tank gages. Production problems are most evident on plots of historic monthly production decline curves. The regular plotting of all monthly produced volumes is one of the best methods of identifying liquid loading problems.

Liquid loading can be corrected by the installation of a fluid removal system, modifying tubing design or operating procedures, using foaming agents, installing compression, enhancing inflow performance, and water shut-off through remediation. This procedure guide focuses on the installation of relatively low cost fluid removal methods associated with fluid removal from stripper wells. These methods include casing plungers, tubing plungers, pumping units, swabbing, and compression.

Casing plungers, while not widely used, afford stripper well operators an option for fluid removal by utilizing a mandrel with rubber seals to provide an interface between the fluid and gas and then utilizing stored reservoir energy to remove the fluids. Casing plungers are an effective means of fluid removal but are limited to wells with high GLR, limited perforation intervals, and casing with good mechanical integrity. This method is typically not able to achieve the lowest bottom hole pressure for optimum reserve recovery. Low maintenance costs are typically associated with this method of liquid removal.

Tubing plungers are effective over a wide range of operating conditions but typically successful with wells with a high GLR. Tubing plungers effectively remove the majority of fluid accumulated in the tubing on a cyclic basis by providing an interface between the fluid and gas and then utilizing stored reservoir energy to remove the fluids. This method is typically not able to achieve the lowest bottom hole pressure for optimum reserve recovery. Low maintenance costs are typically associated with this method of liquid removal.

Pumping units have long been utilized for relieve liquid loading problems associated with stripper wells. This is typically the best method to lower the flowing bottom hole pressure and achieve maximum recovery of oil and gas reserves. However, the higher installation and associated maintenance costs normally encountered when compared with the previous methods of fluid removal can make this method too expensive for stripper well operators.

Swabbing, while long considered one of the most inexpensive forms of fluid removal should only be utilized for those wells with nominal fluid production and a large amount of pocket below the producing interval for fluid accumulation. Swabbing while seemingly inexpensive is often an inefficient fluid removal methods resulting in temporary increases in production after swabbing. Stripper well operators should carefully consider the cumulative annual costs associated with swabbing when compared to the benefits of some other fluid removal method.

Installing compression to lower the wellhead and flowing bottom hole pressure should always be considered as an option for stripper gas wells. This is especially true for mature reservoirs and where multiple wells can be gathered into one system. The application of compression typically results in long term benefits in those areas where high sales line pressure have restricted production. Operators should review their production systems for potential compressor installation applications but should be aware of the initial installation costs and annual operation and maintenance costs associated with any compressor installation. Compression installation by itself to reduce the flowing bottom hole pressure and increase the gas flowrate sufficiently for fluid removal is typically not a method applicable to the low production volumes associated with stripper wells. Furthermore, sizing the proper compressor installation for gas wells with intermittent flow can be difficult.

The following briefly reviews the other correction methods for liquid loading problems and the reasons why they may be inappropriate for stripper gas wells.

While modifying the tubing design (tubing diameter) is often successful in combination with a tubing plunger, by itself, it offers little relief for stripper gas wells. The critical gas flow rate to lift wellbore fluids through 1 ½" tubing or greater, as studied by Turner, Foss and Gaul and others, are in general greater than the flow rates for stripper wells (Appendix 2). For example, a 60 mcfd well with 1½"tubing would require a wellhead pressure of 10 psi while an average stripper well of 10 mcfd well at 10 psi would require ½" tubing. Generally, tubing smaller than 1½" is generally not practical for well servicing, tubing plungers, or beam pump using slim-hole rods. Therefore, modifying tubing design was not a consideration for stripper wells suffering from liquid loading.

Modifying the operating procedures to unload fluids involves periodically shutting in a well to build sufficient pressure to unload the well or by temporarily diverting production to a sales tank at a reduced wellhead pressure for increased gas velocity. Both methods are inefficient, wasting gas and reservoir energy and do not remove all fluids even when automated. The low implementation cost of these methods is attractive, but the additional shut-in time or diversions required result in loss production and revenue. These methods should be viewed as temporary solutions until a more appropriate fluid removal method is selected to increase and maintain production.

The application of foaming agents, soap, or surfactants to a well with liquid loading problems is a common and generally simple method of liquid removal. Studies as early as 1957 investigated the idea of using foaming agents to remove liquids from gas wells. The foaming agent can be introduced to the well in the form of a solid, liquid, gel, powder, or through capillary injection strings. Surfactants, or surface-active agents, act by reducing the surface tension of the water, lightening the column of fluid, thereby giving the reservoir pressure the ability to overcome the fluid column pressure. After a predetermined shut-in time, the liquid and foam are removed by diverting production to a sales tank at a reduced wellhead pressure. The highest cost associated with foamers is often the labor cost due to the hours spent soaping the well, shutting in the well, and then diverting production to the production tank. Automation has minimized the effects of liquid loading by optimizing the treatment program utilizing soap stick launchers and injection pumps, however, the shut-in period to build sufficient pressure to unload the well makes this method inefficient and ultimately another fluid removal method is required.

Enhancing inflow performance through re-stimulation and remedial water shut-off are beyond the scope of this study but should be considered when evaluating potential fluid sources and fluid elimination methods.

Stripper well operation requires the careful consideration of every investment due to the limited income associated with stripper wells where the economic line between success and failure is very thin. Timely and accurate decisions regarding liquid loading problems should be based upon data organized for quick review and not on unsubstantiated opinion. The fluid removal method selected should be effective for the remaining life of the well and based upon specific information. By better defining the source of the liquid loading problem, the better the solution or appropriate fluid removal method will be identified. Unfortunately, stripper well operators often do not track sufficient information to adequately identify the specific problem to implement an effective solution.

The minimum wellfile information should include drilling, cementing, completion, workover and repair reports, shut-in and producing pressure summary, and a wellbore schematic. All summaries prepared should be chronological order. In addition, monthly gas and fluid volumes as well as the GLR, should be plotted and summarized for easy reference and problem analysis.

Ultimately, the focus of every fluid removal method is the same, to maintain a reduced flowing bottom hole pressure to optimize production performance. Successful, economic stripper well production requires the cooperation of everyone involved. Additional training may be required to receive maximum benefit from the fluid removal method employed. Fluid removal equipment in the correct application is often only as effective as those operating it. It is important then to recognize that not all well tenders are equipped with the same set of skills, so where one well tender may succeed with producing a well, another may fail to achieve similar results.

This procedure guide provides the stripper well operator with general guidelines for the evaluation and selection of specific fluid removals methods typically associated with stripper gas wells and not intended as a comprehensive resource.

II. Methodology

A process can be defined as a systematic series of steps designed to result in a desired outcome. However, experience indicates that due to lack of a defined selection process, fluid removal methods are often randomly applied to stripper gas wells experiencing liquid loading problems often resulting in added expense with minimal production increases. This procedure guide provides an evaluation and selection process for the more common forms of fluid removal methods for stripper gas wells including casing plungers, tubing plungers, pumping wells, and swabbing.

Bucaram and Patterson in SPE 26212 entitled "Managing Artificial Lift" indicate that managing artificial lift generally requires information and experience necessary to select the optimum (ultimately the most economical) lift system and the optimum components for that lift system, a continuous production performance monitoring, a data collection system that allows efforts to be focused on problem wells, periodic meetings to discuss problem wells, a central contact that assists with the meetings and provides continuity, information, and contacts from inside the company and the industry, training for company personnel and for contractors, and finally continuous and repeated technology transfer. However, stripper well operators should recognize that the ultimate goal of production operations is to maximize profits and not to maximize production or to minimize equipment failures, since one may not equal the other.

Experience indicates that the process for the analysis of wells experiencing liquid loading problems should include an understanding of applicable fluid removal methods, a decision tree to evaluate other fluid removal methods, an estimate of the individual well ultimate reserves and the final reservoir pressure at economic depletion, a regular review of the complete production history (oil, gas, water, and GLR), a comparison of production history to a type decline curve for abnormal production decline, operating and shut-in pressure information, identification of potential sources of liquid loading, a wellbore schematic, a summary of equipment changes, workovers, and repairs, and a consideration for additional compression. The process should include an estimate of the maximum production performance for the particular fluid removal method, the basic installation procedure, identification of failure paths, a regular discussion of well performance and associated equipment with the well tender, and an estimate of the potential improvement through a fluid removal method change. The process should also include an evaluation of the production results from the implemented change for continued process improvement, and most importantly, the process should be easy to use or it will soon be abandoned.

Simply put, prior to any investment, stripper well operators must first optimize their production with the existing production equipment, and then based upon production, pressure, reserve, and economic analysis, decide if a change in the fluid removal method would optimize the production to the economic depletion of the well.

With regards to the fluid removal method selection process, any well that will still flow is typically non-stripper and any well that has associated liquid production typically has some form of fluid removal method already in place. In the study area, wells are generally on tubing plunger or pump when they reach stripper well production levels. The decision of which production method to utilize should previously have been based upon the GLR. In general, the GLR should be consistent over the life of the well, unless in special circumstances a water drive is present. When a baseline GLR has been established, continued monitoring on monthly basis can help ensure that the fluid removal method is performing as expected.

If a well is currently on pump, continued production by that method becomes a decision based upon past performance, current economics, future reserve recovery, and other opportunities to better utilize the equipment.

As part of this analysis, the operator needs to determine the productive potential of the well experiencing liquid loading problems. A previous study indicates that the productive potential of stripper wells can be estimated by utilizing production decline curves, pressure data, and inflow performance relationships. A full discussion on this method can be found in our previous study, see SPE 73259.

The stripper well operator should always identify those factors that would affect the bottom hole producing pressure when analyzing wells with abnormal production declines. Research indicates that many stripper wells experience abnormal production by failure to reduce the flowing bottom hole producing pressure sufficiently to maximize production. The inability to reduce the flowing bottom hole producing pressure is typically attributable to a misapplication of fluid removal method or a failure in mechanical integrity. Therefore, the operator should be aware of all changes in operating pressures, production volumes, production methods, and especially the producing cycles during the analysis.

The procedure guide is composed of three forms to guide the stripper well operator through liquid removal method selection; the Decision Tree Form, the Data Collection Form, and the Alternate Fluid Removal Method Decision Form. The Decision Tree Form provides a practical four-step process for the application of decision tree analysis to identify the most common causes of liquid loading. The Data Collection Form assists the stripper well operator to gather specific data required for analyzing common stripper well fluid removal methods. Finally, the Alternate Fluid Removal Method Decision Form guides the operator through an economic analysis to determine the most appropriate solution to correct the liquid loading problem.

In addition to the forms previously discussed, also included in the procedure guide Appendix are a swab well summary form, a casing plunger performance form, a shut-in pressure history summary form, three “investment vs. payout” nomagraphs to assist in stripper well decision making, a general wellbore schematic, and a Vogel inflow performance relationship curve.

III. General Steps for Fluid Removal Method Evaluation and Selection

1. **Identify** under performing wells based upon a review of the complete monthly production history plotted on forty-year semi-log paper, current production results, and a comparison to reservoir type curves.
2. **Review** procedure guide section on appropriate fluid removal method
    a. Swab or bailed wells
    b. Casing Plungers
    c. Tuning Plungers
    d. Pumping Wells
3. **Complete** Decision Tree Form
    a. Complete Appropriate Data Collection Form for fluid removal method
    b. Determine production cycles and producing pressures
    c. Estimate maximum production potential – Utilize Vogel's IPR
    d. Estimate remaining reserves (Decline Curve, P/Z, Volumetric Analysis)
    e. Complete Alternate Fluid Removal Method Decision Form
        i. Utilize information from Data Collection Form
        ii. Utilize economic nomagraphs
        iii. Determine appropriate fluid removal method
    f. Review results, re-evaluate as necessary

IV. Quick Reference Guidelines for Fluid Removal Method Selection

The general guidelines for fluid removal method selection are provided in Table 1 including GLR, minimum flowing bottom hole pressure, ability to produce maximum fluid, good casing required, investment capital required ("1" = high, "4" = low), and operator training required.

Table No. 1
Stripper Gas Well Fluid Removal Method Application Guide

Production Method	High GLR	Low GLR	Min. Fbhp	Extensive Completion Interval	Bbls per Cycle	Good Prod Casing	Investment Capital $	Operator Training
Tubing Plunger	√			√	0.25 – 1.0		2	√
Pumping Unit	√	√	√	√	1.0 – 5.0		1	√
Casing Plunger	√				0.25 – 3.0	√	3	√
Swab Well	√		√	√	As swabbed		4	

The following procedures provide the steps necessary to complete the forms and analyze stripper gas wells experiencing liquid loading problems to determine the appropriate fluid removal method.

V. Decision Tree Form Procedure

The Decision Tree Form (Appendix 3) provides a practical four-phase process to quickly and easily assess the application of the fluid removal method for stripper wells. The form provides a methodology for stripper well operators to evaluate the application of fluid removal methods for stripper gas wells by focusing on the GLR and the desired final bottom hole pressure. The Decision Tree Triage Form is divided into three sections, **Phase 1** – Identify the Problem, **Phase 2** – Measure the Problem, **Phase 3** – Solve the Problem, and **Phase 4** -Monitor the Changes and Production.

Phase 1 of the decision tree form, **Identify the Problem**, requests the operator to verify the production data, GLR, decline curve, and forecast to ensure correct data were used. Next the historic and current GLR are compared for significant differences. The entire production history, plotted on forty-year semi-log paper is compared to a reservoir type decline curve, then review for gas or fluid production change. A map of the gas gathering system and location of offset wells should be prepared and reviewed. Then, verify with pumper that the problem still exists to ensure the problem has not already been corrected. Finally, verify metering accuracy and gas gathering system integrity by ensuring charts were integrated correctly and that there are no gas gathering system leaks.

Phase 2 of the decision tree form, **Measure the Problem**, requests the operator to first complete the appropriate data collection form to analyze the liquid loading problem (Appendices 4 - 7) for the following fluid removal methods, Tubing Plunger, Casing Plunger, Pumping Unit, and Swab or Bailed wells. The forms were developed to assist the stripper well operator in evaluating the proper application of fluid removal methods. All of the forms are consistently divided into one section for field personnel to complete, Sections I-III, and one section for office personnel to complete, Sections IV - VII. Accurate data should be utilized to evaluate the fluid removal method, however, reasonable estimates can be utilized if necessary.

Phase 3 of the decision tree form, **Solve the Problem**, requests the operator to Complete the Alternative Production Method Decision Form (Appendix 8) and then determine to complete the recommended well work, review the well for shut-in, sale, or plug and abandon. If no further analysis is required, simply continue to produce any well that cannot be economically remediated. Quick reference nomagraphs are provided for the stripper well operator to determine the rate of return based upon the investment made compared to the production increase. The nomagraphs quickly indicate that very few dollars can be invested for 5 mcfd.

Finally, Phase 4 of the decision tree form, **Monitor the Changes and Production**, requests the operator to measure post change production rates and GLR and to determine if the production meets forecasted rates. If the current rate does not meet forecasted rates then the well should be reevaluated.

While specific failure paths for each fluid removal method are included in the guide, the general failure paths for stripper well operations include complacency, limited well tender training, ignoring well tender recommendations and individual well early production history, incomplete production histories of monthly oil, gas, and water volumes, incomplete pressure and workover summaries, not setting monthly production goals, never checking or changing production cycles, unnecessary gas gathering system restrictions, never comparing integrated produced volumes to sales volumes, and never estimating fluid removal performance.

Further, while specific evaluation tools for each fluid removal method are outlined in the guide, the general evaluation tools for a stripper well operator include production histories, wellfile information, brine hauling reports a wellbore schematic, the weekly well tender reports, swab reports, orifice meter gas sales charts, the well tender, a two pen recorder, an acoustic liquid level device, an amp meter. Special instrumentation like bottom hole pressure recorders and dynamometers are too expensive for most stripper well operators. Other technology is available to improve stripper well operations, but implementation may be cost prohibitive.

The success of a fluid removal method depends upon well tender knowledge and attitude, pipeline capacity, surface equipment surge capacity, and the downhole equipment condition. The chief obstacles faced by well tenders to achieving optimum production are lack of training, lack of information, too many wells, and complacency. It cannot be understated that a well tender's knowledge and acceptance of a production method is vital to stripper well operation. Well tenders need to be on guard that as well conditions change, production cycles need to be adjusted accordingly.

Summaries of artificial lift selection guides compiled by Brown, Clegg, and Weatherford have all included (Appendix 16-19) for reference even though their work exceeds the scope of this project.

A directory of fluid removal service companies and fluid removal equipment manufactures or suppliers, including product, mailing address, and phone number have been provide for easy reference (Appendix 20). A directory of stripper well associations is also included for future reference (Appendix 21).

Individual metering

While many wells are produced through a common sales meter or production facility, once a year tests should be scheduled to determine the production potential of each well, then documented to the wellfile.

Shut-in Pressures – Final word

It is important for the stripper well operator to document all shut-in pressures and to be complete regarding the parameters of the shut-in. While it is recognized that continuous production is important to stripper well profitability and contributes to the ease of operations, oftentimes wells are shut in due to pipeline restrictions, construction, or other events during the course of the year. However, in the event that no shut-in occurs, a planned time should be scheduled to retrieve the shut-in as well as the flowing bottom hole pressure.

VI. Fluid Removal Method Description
Swab or Bailed Wells

The removal of fluid accumulation by swabbing is one of the most basic forms of fluid removal and should only be considered for mature reservoirs with low-pressure that produce a very nominal amount of fluid. Ideally, a swab well should have sufficient pocket below the producing formation for fluid storage between swabbing operations.

Basic Operation

Swabbing or bailing removes fluids from the wellbore by lowering swab tools on steel line, usually inside of a lubricator, to the fluid level. Successive swabbing runs are made until all of the fluid has been removed from the well. Swabbing operations involve a portable swabbing unit or service rig equipped with a steel line, depth meter, swab tools and cups, a lubricator, a swabbing tee, a storage tank, and a one or two man crew. The swab tools can accommodate 1 ½" tubing to 5 ½" casing, although tubing is normally removed for more efficient operation.

Bailing is similar to swabbing but is normally reserved for open-hole completions or shot holes. A 10 to 20 gallon bailer is slowly lowered into the fluid, filled, pulled back to surface, and then emptied. This cycle is repeated until all fluid has been removed from the well. Wells that have been "shot" are generally low-pressure mature wells that require periodic removal of fluids. Swabbing or bailing is one of the earliest methods developed for fluid removal from stripper gas wells and is still utilized throughout the industry.

Cost Considerations

The cost of swabbing should be monitored carefully to ensure that annual expenses do not exceed the total investment of other fluid removal methods over time. The cost for each swabbing may range from $300 to $900 depending on the depth of the well, and the fluid recovered. Swabbing often results in temporary production increases that decline to previous production levels, requiring additional swabbing, the frequency of which is a function of the produced fluid volumes. The periodic removal of only a few barrels of fluid may not be an effective indicator that swabbing is the best method of fluid removal. A small recovery during swabbing is more indicative of low reservoir pressure than fluid production rate. The well may make a small amount of fluid but still load up quickly. A review of the decline curve may indicate that another fluid removal method could sustain production increases better because of a lower flowing bottom hole pressure maintained by continuous fluid removal.

Typical Stripper Well Application Range

- Depth 100 – 7,000'
- Gas Liquid Ratio High
- Fluid Production Nominal
- Large pocket below completion interval
- Established through production testing

General Operational Guidelines

1. Compile and review the complete production history, then compare to type production decline curve for abnormal production decline.
2. Estimate the historic gas to liquid ratio (mcf/barrel)
3. Review the well file for previous swabbing records or well work to identify the total depth, perforations, and any casing or tubing problems.
4. Move in the swabbing unit. Note and record the casing and sales line pressure, and the initial fluid level of the production tank.
5. Release the wellhead pressure to the production tank, and rig up with bare tools.
6. Verify the perforations or producing interval are clear of sand or sediment. Clean out hole to TD for additional storage capacity below the producing interval.
7. Swab the well to the top of the perforations. Note the initial fluid level in the daily report. Swab through the perforations to TD being careful not to get hung in the hole. Swab until hole is dry or note final fluid level.
8. Record the fluid type(s) and the volumes of fluids recovered.
9. Return the well to production and monitor production for effect of fluid influx.
10. If production declines substantially, move in a swab rig in two weeks to thirty days to check for additional fluid influx and swab as necessary.
11. Continue monitoring production and swab results to determine if swabbing is an economic application of fluid removal to optimize production.
12. Any change in fluid removal method to casing swab, tubing plunger, or pumping unit must be based upon GLR, depth, remaining reserves, and payout.
13. Maintain accurate swabbing record to monitor production and future swab volumes.

Evaluation Forms Required

• Decision Tree Form	Appendix 3
• Swab Well Data Collection Form	Appendix 7
• Alternative Fluid Removal Method Decision Form	Appendix 8
• Swabbing or bailing activity report form	Appendix 9
• Shut-in pressure summary form	Appendix 10
• General wellbore schematic	Appendix 11
• Vogel's Inflow Performance Relationship Curve	Appendix 12

Advantages

- Wells can often be produced to depletion
- Simple design and operation
- Annual cost could be relatively low
- Gas and liquids can be produced to sales line pressure if low enough.
- No capital requirement

Disadvantages

- Depending on fluid volumes or reservoir pressure, production increases immediately after swabbing may not be sustained.
- Accumulated annual expenditures may exceed the cost of other fluid removal methods that have higher initial costs.

- Timing of operations may require costs in total hours or dozer expense.
- Production may be delayed waiting on availability of swabbing rig.

Failure Paths

- Not identifying the true effects of fluid production on a well, that is, assuming the volume of fluid recovered during each operation represents the total fluid capability of the well if the bottom hole producing pressure was kept optimized.

- Not removing the tubing to minimize the effects of the hydrostatic pressure of the column of fluid and decreased swabbing efficiency.

- Not preparing a swabbing schedule based upon GLR to swab several wells once mobilized.

Diagnostic Tools

- Production decline curve
- Historic gas liquid ratio
- Well tender proprietary information
- Gas sales orifice meter chart
- Echometer or other sonic fluid level determination instrument
- Single or two-pen pressure recorder
- Swab reports: Fluid levels, fluid volumes, post production results
- BHP bomb – typically too expensive for extensive use on stripper wells.

Important Note –

In order to maintain a wellbore fluid level that would restrict production, the near well bore area is most likely water saturated. Extended swabbing may be required to effectively clean up a well that has been loaded up. The near wellbore storage restricts optimal gas production in three ways:

1. The hydrostatic column of the fluid
2. The fluid in the near well bore area to immediately replace the fluid being removed.
3. The reduction in relative permeability to gas by the presence of fluid.

Casing Plungers

Basic operation:
Casing plungers are designed to remove accumulated liquids from the production casing by isolating the fluids in the wellbore from the gas in the reservoir, and then utilizing reservoir energy to lift the plunger and the fluids above it to the surface. A casing plunger system is comprised of a casing plunger, lubricator or receiver, and a bottom hole stop. Additional surface equipment may include an electronic control box, motor control valve, sensor, drip pot, and gas regulator for pneumatic operation. The plunger is composed of a hollow steel mandrel, designed for 4 ½" casing, approximately 3 feet long, weighing 60 pounds, with multiple rubber sealing elements. Under normal operating conditions the casing plunger should lift 1 to 3 barrels of fluid per cycle. Depending on the volume of fluid produced, the minimum cycles for some wells may be as little as once per month while for other wells the tool may run continuous. There are several thousand casing plungers currently operating in various parts of the country.

A complete cycle for a casing plunger begins with the release of the casing plunger from the surface lubricator. The traveling valve is now in the open position allowing the plunger to free-fall to the bottom hole stop. Gas and fluids pass through the open traveling valve causing very limited interruption to gas production. The plunger's traveling valve closes upon contact with the bottom hole stop. Wellbore fluids that have accumulated above the bottom hole stop are effectively isolated from the gas in the reservoir by the rubber sealing elements. As gas enters the casing, the casing plunger and fluids are lifted to the surface, where production equipment separates the liquids from the gas. The casing plunger enters the surface lubricator, and is captured by a latching mechanism. The traveling valve opens as the latch is engaged allowing for production of the gas below the tool. Gas production continues until the plunger is released to begin another cycle. (After Jet Star sales brochure)

Successful operation of casing plungers can be sustained with regular maintenance, a pressure recorder, and a gas sales orifice meter chart. With this information, the cycle information in regards to the casing pressure, gas sales, and trip time can be documented. Produced fluid and gas volumes should be monitored to optimize plunger cycles. Cycles may be reduced after the well is eventually cleaned up.

Typical Stripper Well Application Range

- Depth 7,500'
- GLR 3 to 5 mcf per barrel minimum, 20 or higher recommended
- Fluid 0.25 to 3 barrels per cycle

General Installation and Operational Guidelines

1. Prior to moving in service rig, obtain a 72-hour shut-in pressure.
2. Move in service unit with lubricator for well cleanout and capacity for handling a tubing string. Record all pertinent information including the date, time, tubing, casing, and sales line pressure and the production tank fluid level prior to beginning installation.
3. Blow well down and remove the tubing and wellhead.
4. Check TD of the well and compare it to the original TD. Clean out 25' rat hole below the completion interval. Determine and record the initial fluid level.
5. Install safety nipple and a full opening ball valve on the production casing.
6. Clean production casing with a casing scraper or broach to TD. The walls of the casing must be clean for successful casing plunger operation.
7. Install the bottom hole stop. A casing stand that locks in a collar above the perforations or on a tubing stand that set on the bottom of hole are available. The stand must be set above the top perforation, ideally 10' to 20'.
8. Swab well to near bottom hole stop, and then close the production casing valve.
9. Install lubricator, insert casing plunger, then connect sales line to the lubricator.
10. Test and correct surface leaks by closing the sales line valve and slowly opening the master valve.
11. Open the master valve and the gas sales line valve.
12. Release the casing plunger from the lubricator. Verify the plunger left the lubricator, and then reset the latch mechanism.
13. Confirm gas sales and continue production.
14. After plunger has surfaced, measure and record the volume of fluid produced
15. Inspect gas sales chart to determine the elapsed time of the casing plunger cycle.
16. The plunger should initially be checked after every trip for the first 5 to 10 trips, then every 30 days or 30 cycles.

Evaluation Forms Required

• Decision Tree Form	Appendix 3
• Casing Plunger Data Collection Form	Appendix 5
• Alternate Production Method Decision Form	Appendix 8
• Shut-in pressure summary form	Appendix 10
• General wellbore schematic	Appendix 11
• Vogel's Inflow Performance Relationship Curve	Appendix 12

Advantages

- Wells can be produced to depletion
- Continuous gas sales, no shut-in time
- All gas produced through sales line and well can be produced at sales line pressure
- No external energy requirements
- Casing plungers can be repaired by one person in the field using common hand tools
- Few moving parts
- Plunger operation not affected by temporary increases in sales line pressure
- No tubulars, other than production casing, are required, except for tubing stop

Disadvantages

- Casing must be free of obstruction and generally free of defects
- Limited to 4 ½" and 5 ½" diameter production casing
- Applicable to limited completion interval spacing
- Manual release method relies on well tender for determining intermittent plunger cycles
- Service rig or swabbing unit required for removing stuck plungers
- Seals subject to deformation, stretching, swelling, tearing, and sticking under extreme conditions
- Not applicable to wells with significant deviation
- Not recommended for wells with unsettled sand or solids
- High-pressure wells can create very large forces across cross sectional area of tool

Cost

- Initial installation, $6,000
- Annual maintenance, $500

Failure Paths

- Insufficient or improper preparation of the casing
- Multiple weights of production casing
- Presence of scale or paraffin in the casing
- Low reservoir pressure
- Improper placement of the bottom hole stop
- Neglecting tool maintenance or periodic seal inspection
- Improper seal replacement

Diagnostic Tools

- Production decline curve
- Well tender proprietary information
- Pressure recorder
- Monthly or weekly orifice meter gas sales chart
- Swabbing reports

Historic Gas/Liquid Ratio
Echometer
Weekly well tender reports
Shut-in pressure
Well records

Additional General Casing Plunger Operational Guidelines – Per Jet Star

Available Lift Pressure	**Barrels per Cycle-4 ½"**	**Barrels per Cycle-5 ½"**
50	1.5	2.3
100	2.9	4.6
150	3.3	7.0
200	4.7	9.3
250	6.1	11.6
300	7.5	13.9
350	8.9	16.2
400	9.3	18.6

Tubing Plungers

"JD Hacksma indicated that the compromise that yields the greatest production is found when cycling the plunger at the maximum frequency possible without killing the well. "

Basic Operation
A tubing plunger is designed to remove accumulated liquids from the production casing by providing an interface or seal (not 100%) between the liquid and gas in the tubing and the energy in the reservoir. After sufficient pressure has built up and a pneumatic valve activated, plunger and fluid are lifted to the surface. The tubing plunger system is comprised of a tubing plunger, a lubricator or receiver, and a bottom hole stop or bumper spring for the plunger set at the bottom of the tubing string. Additional surface equipment usually includes an electronic control box or timer to determine the production cycles, a pneumatically operated motor valve to open and close the production line, a sensor on the tubing to determine the arrival of the plunger, drip pot, and a pressure regulator to control the motor valve. The plunger is typically composed of a hollow steel mandrel, designed for various tubing diameters, approximately 1 to 2 feet long and weighing 5 – 8 pounds, with various sealing element configurations.

The hollow steel plunger mandrel has a fishing neck and is designed for 1 1/4" through 3 1/2" tubing. The five main types of plungers are solid, nylon brush, metal pad, wobble washer, and flexible. A solid plunger is solid steel with either a smooth surface or with concentric grooves over the entire length of the plunger. The brush plunger, good for wells with sand or tubing imperfections, has a brush segment over the length of the body to create the sealing mechanism. Metal pad plungers with spring-activated pads are available in various designs to provide the best mechanical seal against the tubing wall. Wobble washer plungers constructed of shifting steel rings are designed to enhance the liquid seal and to keep the tubing free of paraffin, salt, and scale. Flexible tubing plungers are available as articulated, cup, pad, or brush and are designed to run in tubing with bends or other imperfections.

A complete cycle occurs in three stages, shut-in, unloading, and afterflow. Specifically, the cycle for a tubing plunger consists of a release of the tubing plunger from the surface lubricator with the motor valve on the flow line closed. The plunger travels to bottom through the fluid in the tubing until it reaches the bumper spring. During the shut-in period, gas pressure begins to build in both the tubing and the casing-tubing annulus. The differential between the tubing and casing pressure indicates the approximate hydrostatic column of fluid. Based on time, pressure, differential pressure, or previous plunger velocity the motor valve at the surface opens and the head gas or gas in the tubing feeds into the flowline releasing tubing pressure. Gas accumulated in the casing tubing annulus and in the near wellbore area expands causing the plunger and liquid to travel to the surface. A lubricator - receiver with a spring-loaded cap stops the tubing plunger at the surface. The plunger stays in the lubricator until the after flow is complete and the downstream motor valve closes causing gas flow to cease. This allows the plunger to fall to bottom until activated for another cycle. The fluid recovered during the next cycle enters the tubing during the previous flow period.

Without a tubing plunger as an interface, approximately 75% of an initial slug can be lost from 10,000'. As liquid fall back continues to increase, additional pressure and gas volumes are required to lift subsequent slugs. This incomplete fluid removal increases the bottom hole producing pressure

Effective tubing plunger operation requires training and a clear understanding of inflow performance relationships, plunger efficiency, and system and data maintenance. The key to maximizing production, i.e. inflow performance, is to lower the flowing bottom hole pressure. This somewhat contradicts tubing plunger operation requiring shut-in or off time. JD Hacksma indicated that the compromise that yields the greatest production is found when cycling the plunger at the maximum frequency possible without killing the well. To restate this important principal, the most cycles with the smallest liquid loads equals the lowest bottom hole pressure required, the best inflow performance, and the best production.

Tubing plunger terminology includes off time, on time, and afterflow. Off time is the amount of shut-in time desired or required for the well to accumulate gas pressure. On time is the amount of time desired for the plunger to arrive at the surface and for the well to produce after arrival. Afterflow is the amount of time the well is allowed to produce after the fluid and plunger have surfaced.

Successful operation of tubing plungers can be optimized with the utilization of a pressure recorder, a gas sales orifice meter chart, and regular maintenance. A two-pen pressure recorder is required to monitor the casing and tubing pressures to determine the differential pressure and to maximize the effectiveness of tubing plunger cycles. However, orifice meter charts can yield the minimum and maximum sales line pressures during the cycles and performance throughout the cycle.

Typical Stripper Well Application Range

- Depth To 10,000'
- GLR 15 mcf per barrel minimum
- Fluid ¼ to 3 barrels per cycle

General Installation and Operational Guidelines

1. Prior to moving in service rig, obtain a 72-hour shut-in pressure
2. Move in a service unit with lubricator appropriate for well depth and handling of the tubing string, if necessary. Document the date and time, the tubing, casing, and sales line pressure, and the production tank fluid level prior to beginning well work.
3. Consider removing the tubing and wellhead equipment from the well to accurately access the downhole condition of the well.
4. Determine the TD of the well and compare it to the original TD. Clean out the well to 25' below all completion intervals. Document the initial fluid level in the well in the daily rig report.
5. Inspect, tally, and run the tubing string with a seating nipple on bottom to the top of the perforations. Install a full opening master valve with the same internal diameter as the tubing.

6. Run a two-foot long gauge ring or broach, and drift the internal diameter of the tubing to TD. Micrometer the broach to ensure proper sizing. Compare the depth of the tubing with the tubing tally to confirm setting depth. Record the fluid level in the tubing.
7. Run a bumper spring assembly per the manufacturers specifications. Tag the bumper spring with a wireline to confirm depth of installation, swab as necessary.
8. Close the master valve, remove the wireline assembly, and install a tubing plunger lubricator, manual valves, flow tees, motor valves, supply gas, controller, and two-pen recorder for initial set up.
9. Slowly open the full opening master valve on production tubing allowing the pressure into the lubricator and repair any leaks. Install the plunger in the lubricator.
10. Slowly open the master valve to allow the plunger to fall from the lubricator.
11. Consider chasing the plunger to bottom with a blind box, being careful not to push the plunger.
12. Ensure that all manual valves are in a full open position.
13. Be prepared to cycle the plunger to the production tank for the first couple of cycles if cycling the well to the gas gathering system pressure results in a stalled plunger situation. The flow rate to the production tank should be controlled with a valve or choke to avoid damage by unrestricted travel of the plunger.
14. After the casing pressure and tubing pressure have stabilized, open the well to sales line pressure. The initial off time should be long enough to ensure that the plunger can reach bottom and that sufficient pressure has built to surface plunger with accumulated fluid.
15. Catch the plunger upon its first arrival at surface, close the master valve, bleed down the pressure on the lubricator, then remove and inspect the plunger for damage, paraffin, salt, or scale.
16. Repeat plunger cycles until the well cleans up. Record tubing and casing pressures before and after plunger runs to estimate fluid loads. A two-pen recorder will also record this information as well as the bleed off and build up pressure during cycles. Check tank gages regularly to confirm plunger performance.
17. Shut well in on plunger arrival for low GLR wells (no afterflow) and allow short afterflow for high GLR wells. Based on previous cycle, adjust the cycles as necessary by increasing the afterflow, increasing the number of cycles, or increasing the shut-in time. Some adjustment is always necessary initially, however, electronic pressure switches or sophisticated controllers are available to assist in adjusting the time required for shut-in to build pressure and afterflow to build differential.
18. Confirm plunger arrival and gas sales after turning the well into line and continue production.
19. The plunger should be checked after every trip for the first 5 to 10 trips and then every 7 days or 30 cycles.
20. Inspect the lubricator spring regularly and replace the plunger if worn or damaged.

Advantages

- No external energy requirements
- Can produce well to economic depletion
- Produced gas can go to the sales line if no venting is required.
- Liquid fall back associated with flowing wells is eliminated.

- Easily automated
- Replacement and maintenance by single person using common hand tools
- Low maintenance cost
- A slick line unit is often able to recover stuck or broken plungers
- Applicable to extensive completion intervals
- Good for deviated wells up to 60˚
- Reduced paraffin and scale buildup

Disadvantages
- Well shut-in time is required and gas sales are not continuous.
- Tubing must have consistent I.D. for plunger to work.
- Plunger performance can be affected by temporary increases in sales line pressure.
- Swabbing may be required periodically to assist in some applications.
- Wells with production packers or small casing tubing annulus must have higher GLR.

Evaluation Forms Required

• Decision Tree Form	Appendix 3
• Tubing Plunger Data Collection Form	Appendix 4
• Alternate Fluid Removal Method Decision Form	Appendix 8
• Shut-in Pressure Summary Form	Appendix 10
• General wellbore schematic	Appendix 11
• Vogel's Inflow Performance Relationship Curve	Appendix 12

Cost
- Initial Installation $9,000 including tubing
- Annual Maintenance $500

General Rules of Thumb to Operate a Tubing Plunger:
- Requires minimum 400 scf per barrel of fluid per 1000 feet, or for a 5000 ft. well, 2 mcf/bbl. Experience indicates much higher GLR required for stripper gas wells.
- Low GLR – short or no afterflow
- High GLR – long afterflow – If well slugging fluid evaluate afterflow time.
- The shut-in casing pressure is 1.5 times that of the sales line pressure. (CP-LP)/(CP-LP)
- A minimum of 115% of the tubing volume required for each production cycle.
- The average plunger velocity should be greater than 400 feet per minute.
- Optimum plunger efficiency is generally achieved with small loads and frequent cycles to minimize the flowing bottom hole pressure.
- Multiple wells with the same producing cycle in the same gas gathering system must be scheduled
- Limit the distance from the well to the separator to minimize the backpressure on the well during cycles
- Only requires 1.76 psi continuous differential across to lift a 5 lb 2 3/8" plunger to surface

Failure Paths:

- Lack of well operator training, understanding, or "buy-in"
- Domestic gas usage or production from casing-tubing annulus
- Use of completion packer – limits gas volume available for fluid removal
- Debris or obstructions in the tubing string: Broken or stuck plungers
- Low GLR for low gas volume producing wells
- High fluid production
- High gas sales line pressure
- Lack of production monitoring methods
- Mixed weight tubing string
- Different sized wellhead than tubing string
- Neglecting inspection of plunger diameter periodically after installation

Diagnostic Tools

- Production decline curve
- Historic GLR
- Well tender proprietary information
- Echometer or other sonic fluid level determination
- Two-pen pressure recorder
- Monthly or weekly orifice meter gas sales chart (fast/slow clocks)
- Weekly well tender sheet
- Shut-in pressure and pressure history
- Swabbing reports
- Wellfile
- Tank gages
- Echometer free well analysis software: http://www.echometer.com/software/index.thml
  Combines fluid level, pressure build up, and inflow performance analysis

Note: Consideration should also be given to the effects of annular area available for gas storage in various the tubing-casing combinations found in Table 6.

Table 6

Annular Volume in Cubic Feet as a Function of Tubing Size
5000' Depth

Tubing Size	# per Foot	1.500	2.375	2.785
1.500"	2.75	-	-	-
2.375"	4.70	-	-	-
2.875"	6.40	64	-	-
3.500"	9.20	146	-	-
4.500"	10.50	350	294	222
5.500"	15.50	570	515	427

Pumping Units – Electric, Gas, or Gasoline

Basic Operation

Pumping units are designed to remove accumulated liquids from the production casing by utilizing a downhole pump. The pumping unit system is comprised of a pumping unit, prime mover, bridal, polish rod, sucker rods, tubing, pump, gas anchor, and stuffing box. Additional surface equipment can include an electronic control box or timer to control the production cycles, or an "Autostart" to automatically start a gas engine.

A complete cycle for a pumping unit begins by energizing the pumping unit with electric, natural gas, or gasoline. The casing pressure is typically reduced to the gas gathering system pressure and gas produced twenty-four hours per day. As the pumping unit goes through its cycle, fluid enters the bottom hole pump through the standing valve, displaced through the traveling valve, then is forced to the surface through the continued action of the sucker rods. The well tender determines the number and length of production cycles based upon experience, gas sales chart analysis, or by the well pump off time.

Effective pumping unit operation requires training and a clear understanding of inflow performance relationships, and pump efficiency. However, the key to maximizing production or inflow performance is to maintain a reduced flowing bottom hole pressure. A pumping cycle results in a temporary production increases that declines to previous production levels, requiring periodic pumping, the frequency of which is a function of the produced fluid volumes. The timing of the production cycles is best achieved when electric is available and the well can be put on a timer to optimize the number and duration of the production cycle. Units are also available to automatically start natural gas engines at preset times to achieve similar results.

Various pump and pumping unit designs are available depending on the depth of application. While a significant initial investment is typically involved, the consistent production achieved and the ultimate salvage value of the equipment results in a satisfactory economic investment. One operator was known to have said, “I’ve never lost money on a pumping unit.”

The periodic removal of only a few barrels of fluid may not be an effective indicator that the pumping cycle has been effectively determined. A small recovery during a pumping cycle may indicate a low reservoir pressure rather than a low fluid production rate. The well may make a small amount of fluid but still load up quickly. A review of the gas sales chart and decline curve may indicate that further production cycle optimization could result in sustained production increases better because of a lower flowing bottom hole pressure maintained by continuous fluid removal.

Successful operation of pumping units can be sustained with the utilization of a pressure recorder, a gas sales orifice meter chart, an Echometer, and regular maintenance. While orifice meter charts can yield the cycle time and minimum and maximum sales line pressures, a separate two-pen recorder is required to monitor the casing and tubing differential for determining the effectiveness of day-to-day pumping unit operation.

General Installation Procedure

1. Shut-in the well before installation to establish a reservoir pressure.
2. Move in an appropriate service unit with lubricator for well cleanout and running a tubing string and rods. Record tubing, casing, and sales line pressure prior to beginning any well work.
3. Consider removing the tubing and wellhead equipment from the well to accurately determine the downhole condition of the well.
4. Determine the total depth of well, compare it to the original TD, and then clean out the well as necessary to obtain maximum pocket below the completion interval. Record the fluid level found in the casing in daily report.
5. Inspect, drift, tally, and run the tubing to below the bottom of the perforations with a seating nipple on bottom of sting. Consider a mud anchor or gas anchor.
6. Run appropriate rods and tubing to the seating nipple per the manufacturers specifications or experience.
7. Pump up the well with the rig to confirm pump movement.
8. Complete remainder of wellhead with stuffing box.
9. Hang bridal on horse’s head and ensure unit is level.
10. Check all belts, energize the unit, and then recheck belts and stuffing box.
11. Ensure that all manual valves are in a full open position.
12. Begin with two cycles per day based upon previous fluid production volumes.
13. Confirm pumped off condition with an Echometer. Increase number and length of cycles to optimize fluid production and enhance gas production.
14. The results of the first few days will provide information on the performance of the pumping unit application.

Evaluation Forms Required

• Decision Tree Form	Appendix 3
• Pumping Well Data Collection Form	Appendix 6
• Shut-in Pressure Summary Form	Appendix 10
• General Wellbore Schematic	Appendix 11
• Vogel’s Inflow Performance Relationship Curve	Appendix 12

Advantages

- Continuous production of gas to sales line – no venting
- Can be produced to economic depletion
- Eliminates liquid fall back associated with flowing wells
- Applicable to extensive completion intervals
- Typically 70 – 80% producing efficiency
- Reduced hydrostatic pressure against formation due to pump placement
- High salvage value

Disadvantages

- Initial investment is often high
- Requires outside energy source
- Many moving parts for potential repair: tubing leaks, rod parts, pump failures.

- Rig required for most servicing.
- Paraffin may create significant production problems.

Cost
- Initial installation - $18,000 including tubing
- Annual Maintenance - $3,000

Failure Paths
- Complete entire pumping cycle time required for entire day or week in one cycle.
- Over pump the well, that is, continue pumping in a pumped off condition.
- Never monitor the pump performance.
- Poor handling and makeup technique for rods
- Never service the unit
- Lack of training or understanding

Evaluation Tools
- Production Decline Curve
- Pressure History
- Well Diagnosis Software – often freeware available from suppliers
- Two-pen recorder information
- Tank gages
- Echometer or other sonic fluid level detection device
- Polish rod load cell – see below
- Beam transducer
- Gas sales chart
- Position devices
- Inclinometer
- Power measurement equipment
- Dynamometer - see below
- API Specification 11AX for Subsurface Sucker Rod Pumps and Fittings.

Dynamometer - Polish Rod Transducer Information

Well pumped off	Pump intake pressure
Pump fillage	Current pumping speed
Leaking traveling/standing valves	Maximum/ minimum rod limits
Polish rod and pump hp	Gearbox loaded – unit balanced
Downhole gas separator	

Important Note: Operating in a pumped off condition is expensive damaging equipment, unnecessary wear and tear, and wasting energy. The use of a time clock should always be considered to optimize production. There are now automatic staring gas engines for those locations where electricity is impractical. Consistent fluid removal is essential to stripper gas well production to optimize production.

VII. Appendix

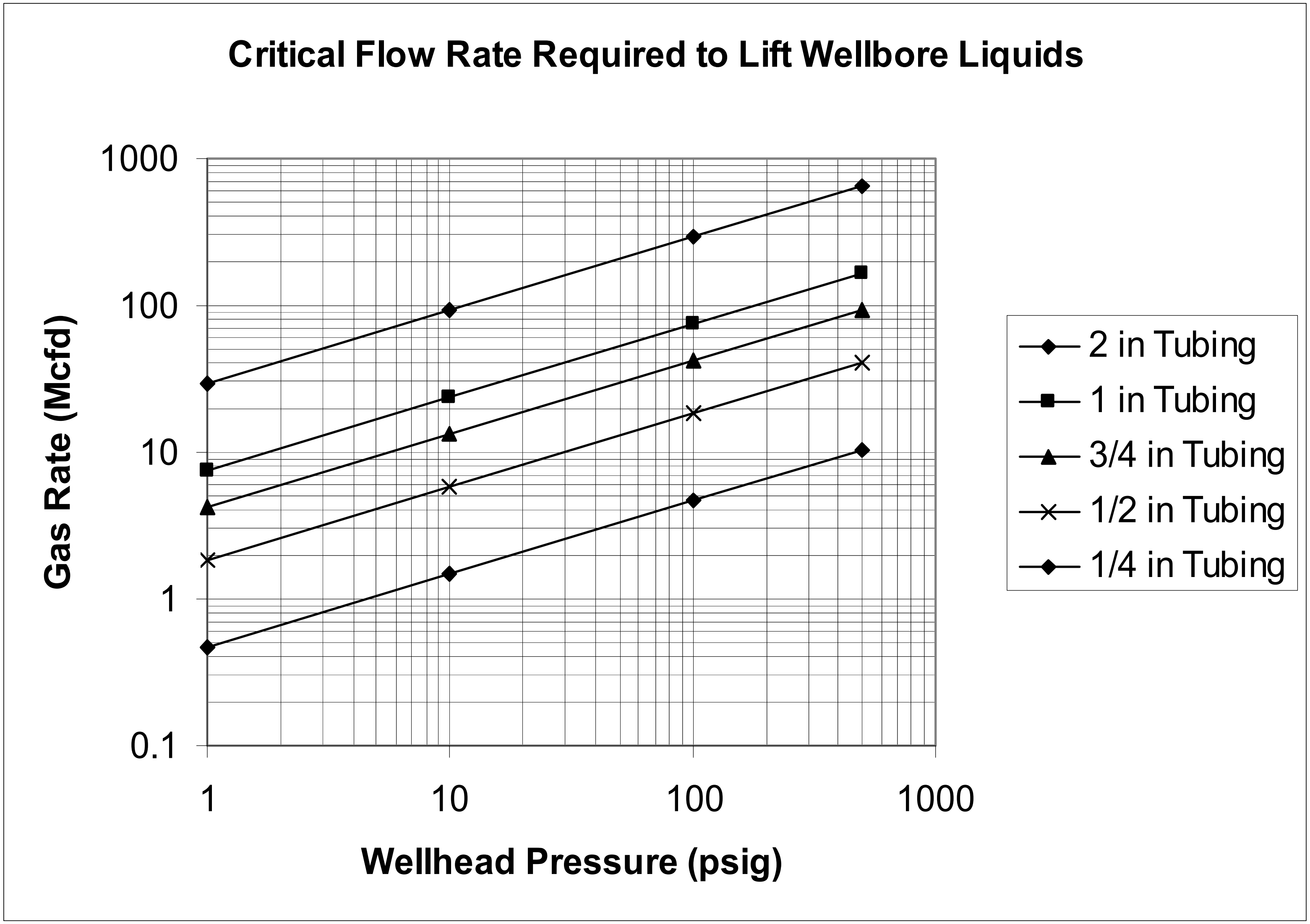
No.

Appendix 1
National Stripper Well Comparison

State	**Wells**			**Production per day per well**		
	Gas	**Oil**	**Total**	**Gas**	**Oil**	**Mcfeq**
AL	1,416	627	2,043	27.8	4.99	62.73
AZ	5	20	25	21.8	2.88	41.96
AR	1,609	3,286	4,895	25.3	2.67	43.99
CA	369	22,244	22,613	21.0	3.87	48.09
CO	10,196	7,618	17,814	15.5	1.40	25.30
ILL	101	18,491	18,592	2.40	1.54	13.18
IN	1,502	5,049	6,551	1.50	1.11	9.27
KS	8,701	35,349	44,050	29.6	1.94	43.18
KY*	13,855	24,585	38,440	14.3	0.26	16.12
LA	9,645	21,091	30,736	7.60	1.98	21.46
MD*	7	0	7	13.2	0.00	13.12
MI	3,165	2,550	5,715	36.0	3.44	60.08
MS	449	376	825	10.1	4.19	39.43
MO	0	327	327	0.00	0.89	6.23
MT	3,752	2,476	6,228	28.1	2.25	43.85
NE	94	1,483	1,577	21.7	3.37	45.29
NM	8,534	12,642	21,186	24.9	2.77	44.29
NY*	5,446	2,638	8,084	5.60	0.19	6.93
ND	63	1,357	1,420	15.1	4.25	44.85
OH*	33,352	28,918	62,270	6.10	0.51	9.67
OK	11,554	60,120	71,674	28.4	2.28	44.36
PA*	35,337	15,170	50,507	9.70	0.40	12.50
SD	54	17	71	23.3	2.55	41.15
TN	191	301	492	15.3	1.72	27.34
TX	29,302	126,028	155,330	22.2	2.93	42.71
UT	626	943	1,569	26.2	4.11	54.97
VA*	133	15	148	42.2	0.84	48.28
WV*	36,816	8,450	45,266	16.3	0.42	19.24
WY	7,433	9,612	17,045	11.1	3.57	36.09
Total	**223,707**	**411,793**	**645,500**	**15.4**	**2.16**	**30.52**
App Basin*	**124,946**	**79,776**	**204,722**	**11.0**	**0.40**	**13.80**

506,397,202 mcf per year
11,458,862 bbl of oil per year

Appendix 2
Turner Critical Flowrate for Various Tubing Sizes



Appendix 3

Decision Tree Form
For
Fluid Removal Method Analysis

Lease Name and Well No. __________________________
Current Fluid Removal Method________
Date of Analysis________

Step Phase I: Identify the Problem

1. Review complete historic monthly production decline curve, and forecast ______________
2. Calculate and compare the historic and current gas liquid ratios, Mcf/bbl ______________
3. Compare monthly production history to reservoir type decline curve ______________
4. Check for gas and total fluid (oil and water) production changes ______________
5. Prepare and review map of gas gathering system and offset well location ______________
6. Check with well tender to verify problem still exists ______________
7. Check for gas metering or integration inaccuracy ______________
8. Check for integrity of gas gathering system ______________

Phase II: Measure the Problem

1. Complete the data **c**ollection form to evaluate current fluid removal method ________
2. Construct and review the wellbore schematic ________
3. Is problem due to fluid removal method, reservoir, or mechanical integrity? ________
4. Is current fluid removal method appropriate for well? Yes / No
5. Have offset wells experienced similar problems? Yes / No / Unknown
6. Can current fluid removal method be modified to produce well to economic limit? Yes / No
7. Check for reservoir depletion and shut-in pressure history ______________
8. What final bottom hole pressure is economically justified? ___________Psi
9. Estimate remaining reserves to justify additional investment? ______________
   Utilize Vogel IPR__, P/Z__ , or production decline curve analysis___

Phase III: Solve the Problem

1. Can production cycles be modified to lower the flowing BHP Yes / No
2. Can the sales line pressure be reduced? (Current______,psi) Yes / No
3. Complete the alternative fluid removal method decision form _____________
4. Review the investment vs. payout nomagraphs _____________
5. Complete the proposed well work? (___________________________) Yes / No
6. Review to Shut-In, Sell, or Plug and Abandon _____________
7. No Further Analysis Required, Continue to Produce, _____________
   Well Cannot be Economically Remediated

Phase IV: Monitor the Changes and Production

1. Measure post change production rates and GLR _____________
2. Does the production meet forecasted rates? _____________
3. If production does not meet forecasted rates, re-evaluate _____________

Appendix 4

Stripper Gas Well
Data Collection Form for Fluid Removal Method Analysis
Production Method - Tubing Plunger

Lease Name and Well No: ______________________________
Date: __________________
Well Tender:___________________

Sections I-III for Field Completion

I. Well Information

Producing Formation(s) ______________
Tubing Pressure: Begin/End ______/_______Psi
Casing Pressure: Begin/End ______/_______Psi
Tubing Plunger System style ______________
Cycles per Day/Min On _______/______Min
Date Cycles Last Adjusted ______________
Previous Cycles per Day/ Min On _____/______Min
Domestic Gas Usage on Casing? Yes / No Move?
Gas Gathering System Operating Psi ______________ Psi
Additional Cycling in Gathering System Yes / No
Would cycle adjustment decrease the fbhp? Yes / No
Would compression assist production? Yes / No

II. Current Daily Production Rate

Oil, Bbl Oil per Day _____BOPD
Gas, Mcf per Day _____MCFD
Water, Bbl Water per Day _____BWPD
Total Fluid per day _____BFPD
Historic GLR_____ Current GLR_______ MCF/BBL
Has production or GLR changed?
MCF/Cycle_____ Bbl/Cycle__________

III. Comments and Recommendations

____
____

Sections IV-VIII for Office Completion

IV. Analytical Data

Perforated Interval(s) ________ - ________
Casing Size and Depth ______ In ________Ft
Tubing Size ________________ In
Tubing Depth ________________ Ft
Sales Line Size ________________ In
Sales Line Length ________________ Ft
Flowing Bottom Hole Pressure (FBHP)________________ Psi
Last Shut-in date and Pressure (SIBHP)________________ Psi

V. Vogel Inflow Performance Relationship Analysis*

Ratio of FBHP/SIBHP __________________
Estimated Maximum Production Rate ______BOPD_____MCFD
*(Or estimated by production decline curve analysis)

VI. Forecasted Rates of Production by Current Production Method

Oil, Bbl Oil per Day _____BOPD _____BFPD
Gas, Mcf per Day _____MCFD
Water, Bbl Water per Day _____BWPD
GLR _____ MCF/BBL

VII. Date and Description of Last Well Work

____
____

VIII. Comments and Recommendations

____
____

Appendix 5

Stripper Gas Well
Data Collection Form for Fluid Removal Method Analysis
Production Method - Casing Plunger

Lease Name and Well No: ______________________________
Date: _________________
Well Tender:__________________

Sections I-III for Field Completion

I. Well Information

Producing Formation(s)	______________	
Flowing Casing Pressure	______________	Psi
Casing Plunger Style	______________	
Trips per Week	______________	
Cycles per Day / Min On	______/_______	Min
Domestic Gas Usage	Yes / No	
Gas Gathering System Operating Psi	______________	Psi
Additional Cycling in Gathering System	Yes / No	
Last Fluid Level Shot: Date/Depth	________/______	Ft

II. Current Daily Production Rate

Oil, Bbl Oil per Day	______	BOPD
Gas, Mcf per Day	______	MCFD
Water, Bbl Water per Day	______	BWPD

Historic GLR________ Current GLR_______
Typical Bbl/Cycle__________

III. Comments and Recommendations

____
____
____
____

Sections IV-VIII for Office Completion

IV. Analytical Data

Perforated Interval(s)	_______ -________	
Casing Size and Depth	_____ In _______	Ft
Flow	Intermittent / Continuous	
Stand Depth	_______________	Ft
Sales Line Size	_______________	In
Sales Line Length	_______________	Ft
Flowing Bottom Hole Pressure (FBHP)	_______________	Psi
Last Shut-in Date and Pressure (SIBHP)	_______________	Psi

V. Vogel Inflow Performance Relationship Analysis*

Ratio of FBHP/SIBHP ________________
Estimated Maximum Production Rate _____ BOPD_____MCFD
*(Or estimated by production decline curve analysis

VI. Forecasted Rates of Production by Current Production Method

Oil, Bbl Oil per Day	______	BOPD
Gas, Mcf per Day	______	MCFD
Water, Bbl Water per Day	______	BWPD
GLR	_____	MCF/BBL

VII. Date and Description of Last Well Work

____
____

VIII. Comments and Recommendations

____
____
____
____

Appendix 6

Stripper Gas Well
Data Collection Form for Fluid Removal Method Analysis
Production Method - Pumping Unit Well

Lease Name and Well No: ______________________________
Date: _________________
Well Tender: __________________

Sections I-III for Field Completion

I. Well Information

Prime Mover *	__________________	
Producing Formation(s)	__________________	
Flowing Tubing Pressure	__________________	Psi
Flowing Casing Pressure	__________________	Psi
Pump Schedule	__________________	
Stroke Length	__________________	In
Unit Speed	__________________	SPM
Date Cycles Last Adjusted	__________________	
Previous Cycles	__________________	
Domestic Gas Usage	Yes / No	
Gas Gathering System Operating Psi	_________________	Psi
Last Fluid Level Shot Date / Depth	_________/_________	Ft

*Electric-PJEM, Gas, Gasoline, or Propane-PJGE

II. Current Daily Production Rate

Oil, Bbl Oil per Day	______	BOPD
Gas, Mcf per Day	______	MCFD
Water, Bbl Water Day	______	BWPD

Historic GLR_______ Current GLR_______

III. Comments and Recommendations

____
____
____

Sections IV-VIII for Office Completion

IV. Analytical Data

Perforated Interval(s)	_______ - ________	
Casing Size and Depth	_____ In ________	Ft
Tubing Size	_______________	In
Depth of Tubing	_______________	Ft
Rod Size	_______________	In
Pump Description	_______________	
Sales Line Size	_______________	Ft
Sales Line Length	_______________	Ft
Flowing Bottom Hole Pressure (FBHP)	_______________	Psi
Last Shut-in Pressure and Date (SIBHP)	_______/________	Psi

V. Vogel Inflow Performance Relationship Analysis*

Ratio of FBHP/SIBHP ________________
Estimated Maximum Production Rate _____ BOPD_____MCFD
*(Or estimated by production decline curve analysis

VI. Forecasted Rates of Production by Current Production Method

Oil, Bbl Oil per Day	_____	BOPD
Gas, Mcf per Day	_____	MCFD
Water, Bbl Water Day	______	BWPD
GLR	_____	MCF/BBL

VII. Date and Description of Last Well Work

____

VIII. Comments and Recommendations

____
____
____

Appendix 7

Stripper Gas Well
Data Collection Form for Fluid Removal Method Analysis
Production Method - Swab Well or Bailed Well

Sections I-III for Field Completion

I. Well Information

Producing Formation(s) ______________
Flowing Tubing Pressure – Swab N/A ______________ Psi
Flowing Casing Pressure ______________ Psi
Date Last Swabbed ______________
Fluid Recovered ______________ Bbls
Domestic Gas Usage Yes / No
Gas Gathering System Operating Psi ______________ Psi
Last Fluid Level Shot Date / Depth _______/_______ Ft
Can gas gathering system pressure be reduced? Yes / No
Are there restrictions in the gas sales line? Yes / No
Review previous swabbing reports.

II. Current Daily Production Rate

Oil, Bbl Oil per Day _____ BOPD
Gas, Mcf per Day _____ MCFD
Water, Bbl Water Day _____ BWPD
Historic GLR ______ MCF/BBL
Current GLR _______MCF/BBL

III. Comments and Recommendations

____
____
____

Lease Name and Well No: ______________________________
Date: _________________
Well Tender:__________________

Sections IV-VIII for Office Completion

IV. Analytical Data

Perforated Interval(s) ________ - _______
Casing Size and Depth _____ In ________Ft
Tubing Size – Swab N/A _______________ In
Depth of Tubing – Swab N/A _______________ Ft
Sales Line Size _______________ In
Sales Line Length _______________ Ft
Flowing Bottom Hole Pressure (FBHP) _______________ Psi
Last Shut-in Date and Pressure (SIBHP) _______________ Psi

V. Vogel Inflow Performance Relationship Analysis*

Ratio of FBHP/SIBHP ________________
Estimated Maximum Production Rate_____ BOPD_____ MCFD
*(Or estimated by production decline curve analysis)

VI. Forecasted Rates of Production by Current Production Method

Oil, Bbl Oil per Week / Day _____ BOPD
Gas, Mcf per Week / Day _____ MCFD
Water, Bbl Water Day _____ BWPD
GLR _____ MCF/BBL

VII. Date and Description of Last Well Work

Review swabbing history, sustained production, and associated costs.
Production immediately after last swab?_____MCFD
How long did production increase last?______Months/Weeks/Days

VIII. Comments and Recommendations

____
____
____

Appendix 8

Stripper Well
Alternative Fluid Removal Method Decision Form

Lease Name and Well Number ____________________________
I. Current Production Method ____________________________ **Current BOPD ____MCFD ____MCFEQ ____GLR_____**
Historic GLR______

II. Maximum Flow Rate Predicted by Vogel Inflow Performance Relationship Analysis and/or Production Decline Curve Analysis
Ratio of FBHP/SIBHP ____________________________
Estimated Maximum Production Rate ___ Bopd ___ Mcfd ___Mcfeq ____GLR Estimated Remaining Reserves________Mcf_______BO
Estimated Final BHP _____ Psi

III. Alternative Production Method**	**Forecasted Rates of Production by Production Method**	**Cost of Alternative Production Method**	**Economic Analysis M$/Mcfeqd**	**Payout, Months**	**NPV**
Swab or Flow Well	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______
Tubing Plunger	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______
Casing Plunger	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______
Pumping Unit	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______
Compression Installation	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______
Pipeline/Meter Installation	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______
Other ________________	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______

****This comparison should determine which fluid removal method is the most economical to produce the well to depletion.**

IV. Comments and Recommendation

____
____
____
____

While M$ per mcfeqd and payout measured in months are good economic indicators to compare production method alternatives, the calculation of a Net Present Value (NPV) based upon future reserves and cash flow should be considered as the superior method for determining economic benefit.

Appendix 9

Lease Name and Well No: ________________________________
Date: __________________
Production Method – Swabbing Record Summary Form

Date / Cost	Last Shut-In Pressure, Psi	Initial Wellhead Pressure, Psi	Initial Swab Fluid Level, Feet	Final Swab Fluid Level, Feet	Total Depth, Feet	Volume, Barrels	Initial or Overnight Sales, mcf
_____/_____	_________	_________	___________	_________	_________	_________	__________________
_____/_____	_________	_________	___________	_________	_________	_________	__________________
_____/_____	_________	_________	___________	_________	_________	_________	__________________
_____/_____	_________	_________	___________	_________	_________	_________	__________________
_____/_____	_________	_________	___________	_________	_________	_________	__________________
_____/_____	_________	_________	___________	_________	_________	_________	__________________
_____/_____	_________	_________	___________	_________	_________	_________	__________________
_____/_____	_________	_________	___________	_________	_________	_________	__________________
_____/_____	_________	_________	___________	_________	_________	_________	__________________

III. Comments and Recommendations____

____

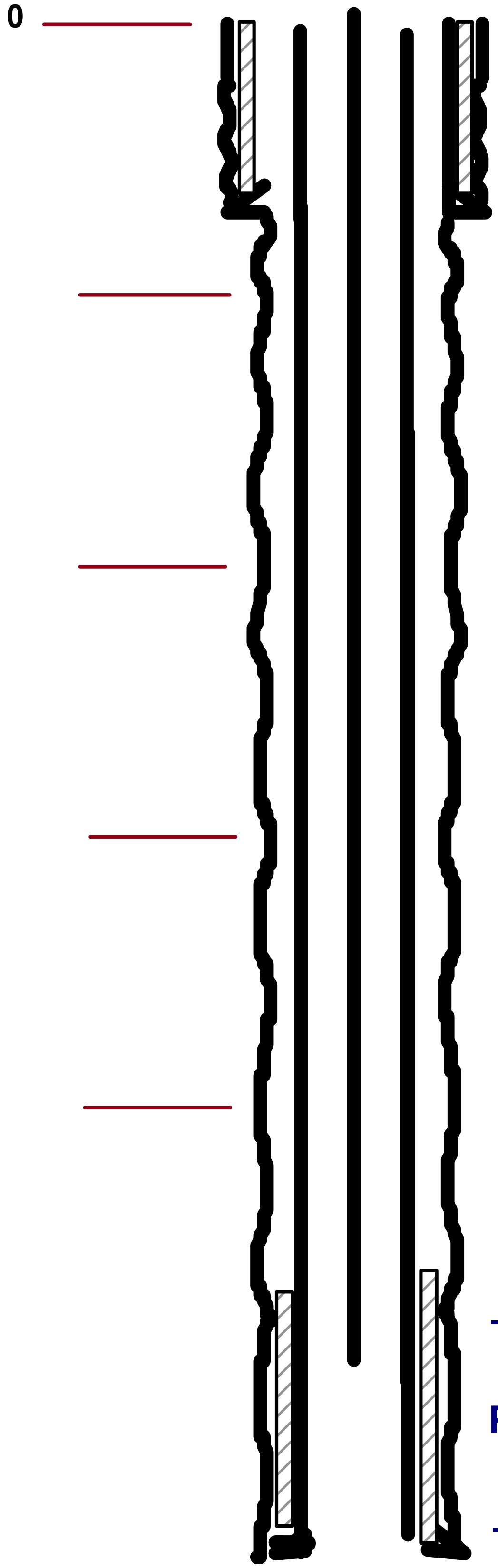
Appendix 10

Lease Name and Well No: ______________________________
Shut-in Pressure Summary Form

Date	Starting Shut-In Pressure, Psi	Final Shut-In Pressure, Psi	Days, Hrs	Mcf, Gas To Date	Bbl, Water To Date	Bbl, Oil To Date	Total Fluid Barrels	GLR

This form provides an excellent summary for P/Z analysis.

General Wellbore Schematic



8-5/8" Surface Casing Set at ________'

____" Tubing Set at: _________SN ___________MA

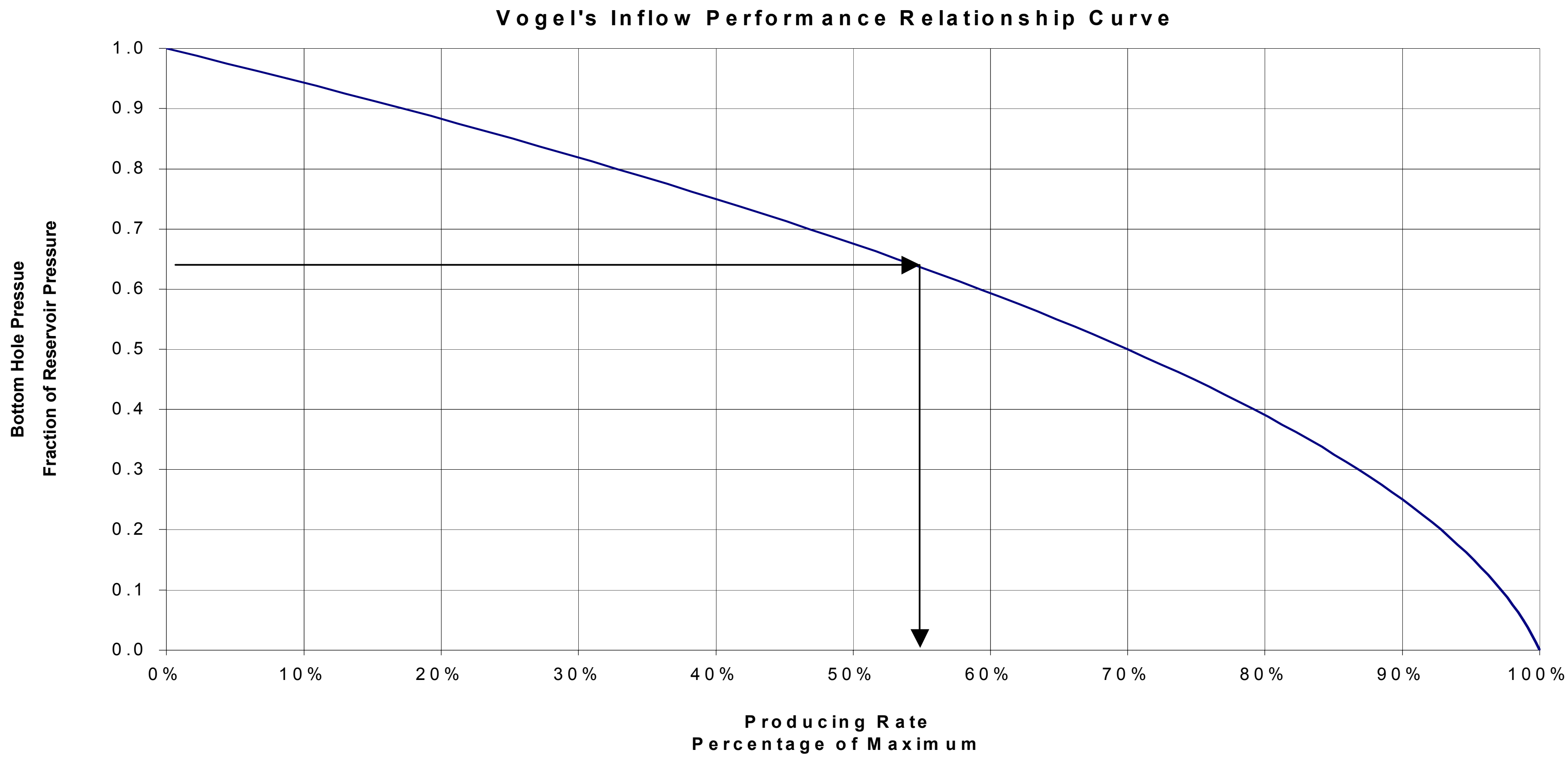
Perforations: _________ - ____________

____" Casing Set at: _________

Total Depth of Well:_________

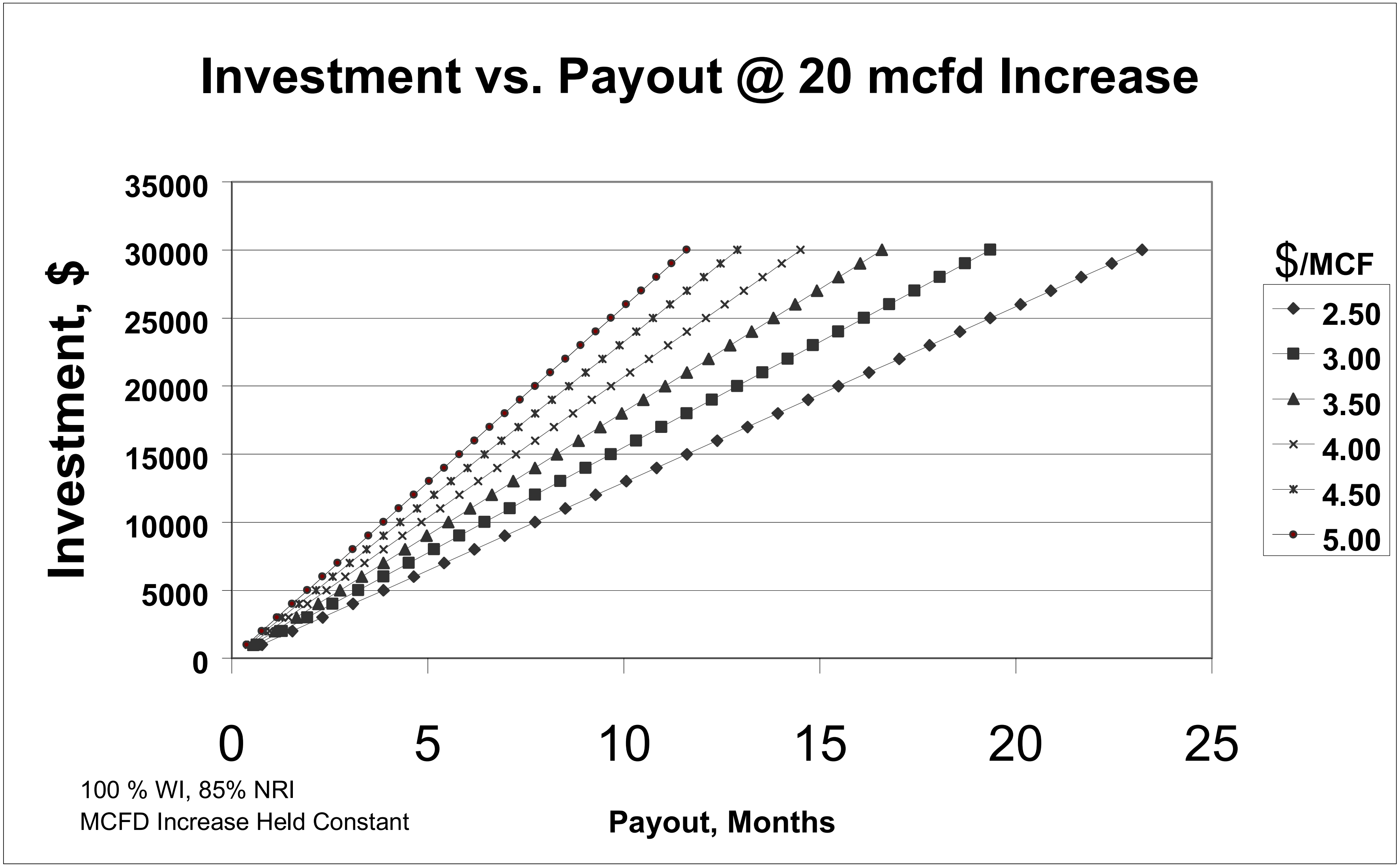
Lease Name and Well No. _____________________

Appendix 12

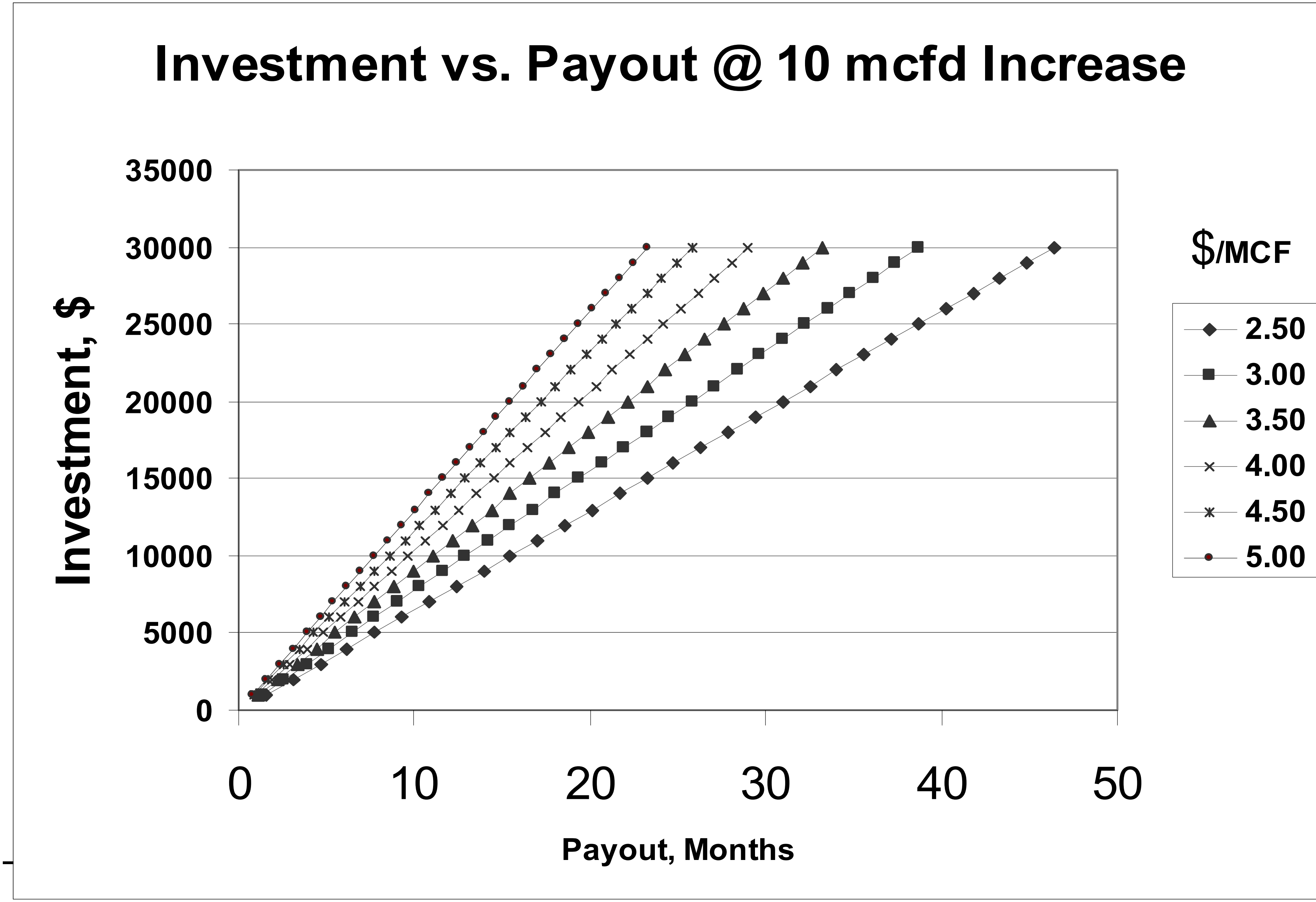


1. Divide the flowing bottom hole pressure by the shut-in bottom hole pressure, fbhp/sibhp.
2. Enter chart from left. Draw line to curve then drop down to determine percentage of maximum possible production being achieved.
3. Divide current production rate by percentage to determine maximum production rate possible.
4. For example: 195 psi / 300 psi = 0.65 ; 0.65 = 0.55% of Maximum Producing Rate ; 10 mcfd / 0.55 = 18 mcfd maximum production

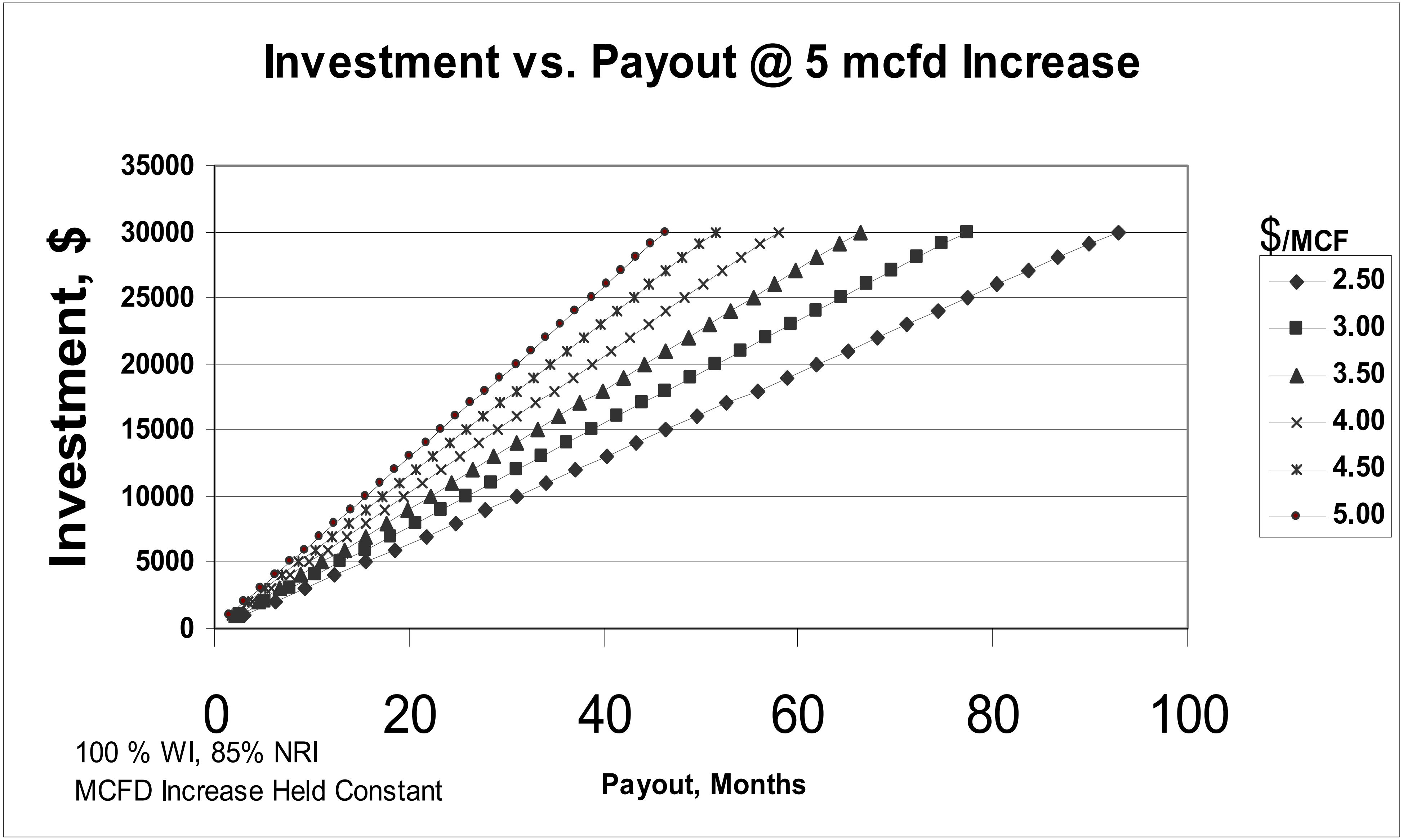
Appendix 13
Investment vs. Payout @ 20 MCFD Increase



Appendix 14
Investment vs. Payout @ 10 MCFD Increase



Appendix 15
Investment vs. Payout @ 5 MCFD Increase



Appendix 16
Weatherford Artificial Lift Elimination Process

Appendix 16 - Weatherford Artificial Lift Elimination Process

Criteria/Lift	Rod Lift	Progressive Cavity	Gas Lift	Plunger Lift	Hydraulic Piston Pump	Hydraulic Jet Lift	Electric Submersible
Operating Depth, Ft	100 –16,000	2,000 - 6,000	5,000 - 15,000	8,000 – 19,000	7,000 - 17,000	5,000 - 15,000	1,000 - 16,000
Operating Volume, Bbl per Day	5 – 6,000	5 – 4,500	100 – 30,000	1 – 200	50 – 8,000	300 – 15,000	200 to 40,000
Operating Temp, F	100 - 550	75 – 325	100 – 400	120 – 500	100 - 500	100 – 500	100 – 400
Corrosion Handling	Good to Excellent	Fair	Good to Excellent	Excellent	Good	Excellent	Good
Gas Handling	Fair to Good	Good	Excellent	Excellent	Fair	Good	Poor to Fair
Solids Handling	Fair to Good	Excellent	Good	Fair	Poor	Good	Poor to Fair
Fluid Gravity, API	>8	<35	>15	> 15	> 8	> 8	>10
Servicing	Workover or Pulling Rig	Workover or Pulling Rig	Wireline or Workover Rig	Wireline or Wellhead Catcher	Wireline or Hydraulic	Wireline or Hydraulic	Workover or Pulling Rig
Prime Mover	Gas or Electric	Gas or Electric	Compressor	Well's Natural Energy	Multi-cylinder or Electric	Multi-cylinder or Electric	Electric
Overall System Efficiency	45 - 60	40 – 70	10 - 30	N/A	45 - 55	10 - 30	35 – 60

Appendix 17
Brown's Relative Advantages of Artificial Lift Systems

Appendix 17 - Relative advantages of artificial lift systems (from Brown, 1982)

Rod Pumping	**Hydraulic Piston Pumping**	**Electric Submersible Pump**	**Gas Lift**	**Hydraulic Jet Pump**	**Plunger Lift**	**Progressive Cavity Pump**
Relatively simple system design	500 bpd from 15,000' installed to 18,000'		Can handle large volume of solids	Has no moving parts	Very inexpensive installation	Moderate Cost
Units easily changed to other wells with minimum cost	Not so depth limited-can lift large volumes from great depths	Can handle volumes to 20,000 bpd	Can handle volumes to 50,000 bpd	Can handle volumes to 30,000 bpd		High electrical efficiency
Efficient, simple, and easy for field people to operate	Power source can be remotely located	Simple to operate	Power source can be remotely located	Power source can be remotely located		
Applicable to slim holes and multiple completions	Applicable to multiple completions	Lifting cost for high volumes generally very low	Lifting gassy wells is no problem		Applicable to high gas oil ratio wells	
Can pump down to very low pressure	Can pump down to fairly low pressure				Can be used to unload liquid from gas wells	
System usually vented for gas separation and fluid level soundings	Downhole pumps can be circulated out in free system		Sometimes serviceable with a wireline unit	Retrievable without pulling tubing	Retrievable without pulling tubing	Some types retrievable with rods
Flexible-can match displacement rate to well capability as well declines	Flexible-can match displacement rate to well capability as well declines		Fairly flexible-convertible from continuous to intermittent as well declines	Power fluid does not have to so clean as for hydraulic piston pumping	Automatically keeps tubing clean of paraffin and scale	
Analyzable	Analyzable	Easy to install downhole pressure sensor via cable	Easy to obtain downhole pressures and gradients			
Can lift high temperature and viscous oils	Crooked holes present minimal problems	Crooked holes present no problems	Crooked holes present no problems	Crooked holes present no problems	Can be used in conjunction with intermittent gas lift	
Can use gas or electricity as power source	Can use gas or electricity as power source			Can use water as a power source		Can use downhole motors that handle sand and viscous fluid

Appendix 17 - continued
Brown's Relative Advantages of Artificial Lift Systems

Rod Pumping	**Hydraulic Piston Pumping**	**Electric Submersible Pump**	**Gas Lift**	**Hydraulic Jet Pump**	**Plunger Lift**	**Progressive Cavity Pump**
Applicable to pump off control if electrified	Easy to pump in cycles by time clock					
Availability in different sizes	Adjustable gear box for triplex offers flexibility	Availability in different sizes				
Hollow sucker rods are available for slim hole completions and ease of inhibitor treatment	Unobtrusive in urban locations	Unobtrusive in urban locations	Unobtrusive in urban locations	Unobtrusive in urban locations		Low profile
Have pumps with double valving that pump on both upstroke and downstroke	Applicable offshore	Applicable offshore	Applicable offshore	Applicable offshore		

Appendix 18
Brown's Relative Disadvantages of Artificial Lift Systems

Rod Pumping	Hydraulic Piston Pumping	Electric Submersible Pump	Gas Lift	Hydraulic Jet Pump	Plunger Lift	Progressive Cavity Pump
Crooked holes present a friction problem	Power oil systems are a fire hazard	Not applicable to multiple completions	Lift gas is not always available	Relatively inefficient lift mechanism	May not take well to depletion, hence eventually requiring another lift mechanism	Elastomers in stator swell in some fluids
High solids production is troublesome	Large oil inventory required in power oil system which detracts from profitability	Only applicable with electric power	Not efficient in lifting small fields or one well leases	Requires at least 20% submergence to approach best lift efficiency	Good for low rate wells only normally less than 200 bpd	POC is difficult
Gassy wells usually lower volumetric efficiency	High solids production is troublesome	High voltage (1,000 V) are necessary	Difficult to lift emulsions and viscous crudes	Design of system is more complex	Requires more engineering supervision to adjust properly	Lose efficiency with depth
Is depth limited, primarily due to rod capability	Operating costs are sometimes higher	Impractical in shallow low volume wells	Not efficient for one well leases if compression equipment is required	Pump may cavitate under certain conditions	Danger exists in plunger reaching to high a velocity and causing surface damage	Rotating rods wear tubing: windup and afterspin of rods increase with depth
Obtrusive in urban locations	Usually susceptible to gas interference- usually not vented	Expensive to change equipment to match declining well capability	Gas freezing and hydrate problems	Very sensitive to any changes in back pressure	Communication between tubing and casing required for good operation unless used in conjunction with gas lift	
Tubing cannot be internally coated for corrosion	Vented installations are more expensive because of extra tubing required	Cable causes problems in handling tubulars	Problems with dirty surface lines	The producing of free gas through the pump causes reduction in ability		
H2S limits depth at which a large volume pump can be set	Treating for scale below packer is difficult	Cables deteriorate in high temperatures	Some difficulty in analyzing properly without engineering supervision	Power oil systems are fire hazard		
Limitations of downhole pump design in small diameter casing	Not easy for field personnel to troubleshoot	System is depth limited, 10,000, due to cable cost and inability to install enough power downhole	Cannot effectively produce deep wells to abandonment	High surface power fluid pressures are required.		
	Difficult to obtain valid well tests in low volume wells	Gas and solids production are troublesome	Requires makeup gas in rotative systems			
	Requires two strings of tubing for some installations	Not easily analyzable unless good engineering know how	Casing must withstand lift pressures			

Appendix 18 - continued
Brown's Relative Disadvantages of Artificial Lift Systems

Rod Pumping	Hydraulic Piston Pumping	Electric Submersible Pump	Gas Lift	Hydraulic Jet Pump	Plunger Lift	Progressive Cavity Pump
	Safety problem for high surface pressure power oil	Casing size limitation				
	Lost of power oil in surface equipment failure	Cannot be set below fluid entry without a shroud to route fluid by the motor				
		Shroud allows corrosion inhibitor to protect outside of motor				
		More downtime when problems are encountered due to entire unit being downhole				

Appendix 19
Clegg's Artificial Lift Design Consideration Comparison

(after Clegg, et al., 12/1993)

	Rod Pump	Progressive Cavity Pump	Electric Submersible Pump	Hydraulic Reciprocating	Hydraulic Jet	Gas Lift	Intermittent Gas Lift	Plunger Lift
Capital Cost Table 4A	Low to moderate	Low	Low with electric	Competitive to rod pump	Competitive to rod pump	Equipment low, compression high	Same as gas lift	Very low without compression
Downhole Equipment Table 4B	Reasonably good rod design and operating practices needed	Good design and operating practices needed	Requires proper cable installation, in addition to motor, pumps, seals, etc.	Proper pump sizing and operating practices essential.	Requires computer design programs for sizing.	Good valve design and spacing essential.	Unload to bottom with gas lift valves, cons. chamber for high PI low bhp wells	Operating practices have to be tailored to each well for optimization.
Efficiency(HHP/HP) Table 4C	Excellent	Excellent	Good	Fair to Good	Fair to poor	Fair	Poor	Excellent
Flexibility Table 4D	Excellent	Fair	Poor	Good to excellent	Good to excellent	Excellent	Good	Good
Miscellaneous Problems Table 4E	Stuffing box leakage	Limited service	Requires reliable electric	Power fluids solids control essential	More tolerant of power fluid solids	Highly reliable. Dehydrated gas required	Labor intensive	Sticking is major problem
Operating Costs Table 4F	Low	Potentially Low	Varies	Often higher than rod pump	Higher power costs	Well cost low	Well costs low	Very low
System reliability Table 4G	Excellent	Good	Varies	Good	Good	Excellent	Excellent	Good
Salvage Value Table 4H	Excellent	Fair to poor	Fair	Fair	Good	Fair	Fair	Fair
System Overall Table 4I	Straight forward	Simple to install and operate	Fairly simple to design but requires good rate data	Simple manual or computer design	Computer design well application	Adequate high pressure, dry, non-corrosive supply needed.	Adequate high pressure, dry, non-corrosive supply needed.	Simple to design, install, operate
Usage/Outlook Table 4J	Excellent	Limited to shallow	Excellent for high rates	Often default artificial lift	Good for higher volumes	Good, flexible, high rate	Often default artificial lift	Essentially low liquid, highGLR
Casing Size Limits Table 4K	Problems only in high rate wells	Normally no problem for 4 ½ and greater	Size will limit use of motors and pumps	Parallel free and closed systems – lg	Dual comp. Require larger casing	Sm <1000 bpd: Lg >5000 bpd	Small casing suitable for low volume	Small casing suitable for low volume
Depth Limits-Table 4L	11000' 16,000 max	5,000 6,000 max	10,000 15,000 max	10,000 20,000 max	10,000 15,000 max	10,000 15,000 max	10,000 10,000 max	8,000 19,000 max
Intake Capabilities Table 4M	Excellent	Good	Fair	Fair	Poor to fair	Poor	Fair	Good
Noise Levels Table 4N	Fair	Good	Excellent	Good	Good	Low Compressor?	Low Compressor?	Excellent

Appendix 19 - continued
Clegg's Artificial Lift Design Consideration Comparison

	Rod Pump	Progressive Cavity Pump	Electric Submersible Pump	Hydraulic Reciprocating	Hydraulic Jet	Gas Lift	Intermittent Gas Lift	Plunger Lift
Obtrusiveness-Table 4O	Poor to fair	Good	Good	Fair to good	Fair to good	Good	Good	Good
Prime Mover Flexibility Table 4P	Good	Good	Fair	Excellent	Excellent	Good	Good	Not applicable
Surveillance Table 4Q	Excellent	Fair	Fair	Good to fair	Good to fair	Good to excellent	Fair	Good
Relative Ease of Well Testing - Table 4R	Good	Good	Good	Fair	Fair	Fair	Poor	Good
Time Cycle and Pump off Controllers Table 4S	Excellent	Poor	Poor	Poor	Poor	Not applicable	Poor	Not applicable
Corrosion/Scale Handling Ability Table 4T	Good to excellent	Good	Fair	Good to excellent	Good to excellent	Good	Good	Fair
Crooked/Deviated Holes Table 4U	Fair	Poor to fair	Good	Excellent	Excellent	Excellent	Excellent	Excellent
Duals Application Table 4V	Fair	Unknown	Unknown	Fair	Fair	Fair	Fair	Unknown
Gas Handling Ability Table 4W	Good	Poor	Poor	Food to fair	Good to fair	Excellent	Excellent	Excellent
Offshore Application Table 4X	Poor	Poor	Good	Fair	Good	Excellent	Poor	Excellent
Paraffin Handling Capability - Table 4Y	Good to excellent	Fair	Fair	Good to excellent	Good to excellent	Good	Good	Excellent
Slim hole Completions Table 4Z	Feasible	Feasible	Unknown	Possible	Possible	Feasible	Feasible	Good
Solids/Sand Handling Ability Table 4AA	Fair	Excellent	Poor	Poor	Fair to good	Excellent	Fair	Poor
Temperature Limitation Table 4AB	Excellent 550	Fair 250	Fair 250 -400	Excellent 500	Excellent 600	Excellent 400	Excellent 400	Excellent
High Viscosity Fluid Handling Table 4AC	Good <200 cp	Excellent	Fair	Good	Good to excellent	Fair	Fair	Not applicable
High Volume Lift Capabilities-Table 4AD	Fair	Poor	Excellent	Good	Excellent	Excellent	Poor	Poor
Low Volume Lift Capabilities-Table 4AE	Excellent <100 bfpd	Excellent <100 bfpd	Poor <400 bfpd	Fair 100 – 300 bfpd	Fair 200 bpd @ 4000'	Fair 200 bpd 2"	Good ½ to 4 bbls per cycle	Excellent 1 to 2 bpd with high GLR

Appendix 20
Directory of Fluid Removal Service Companies
or Equipment Manufacturers

Company	Product	Address	City	State	Zip	Phone
American Int.	Pumping Units	905 South Grandview	Odessa	TX	79761	915-334-4500
Aquaclear	Foamers	608 Virginia Street	Charleston	WV	25301	304-343-4792
Baker Petrolite	Foamer	12645 W. Airport Rd	Sugar Land	TX	77478	800-231-3606
CFER Technologies	Production Enhancement	200 Karl Clark Rd.	Edmonton	CN	T6N1H2	780-450-8989
DIS	Chemical Injection		Houston	TX		800-817-7950
Echometer Co.	Diagnostic Equipment	5001 Ditto Lane	Wichita Falls	TX	76302	940-767-4334
EDI	Tubing Plungers	228 Pike Street	Marietta	OH	45750	740-374-4301
EP Solutions	Artificial Lift Systems	15995 N. Barkers	Houston	TX	77079	832-201-4200
Ferguson-Beauregard	Tubing Plungers	PO Box 130158	Tyler	TX	75713-0158	903-561-4851
Harbison-Fischer	Pumps	PO Box 2477	Ft. Worth	TX	76113	817-297-2211
Jensen	Pumping Units	PO Box 1509	Coffeyville	TX	67337	318-251-5700
Logic Plunger Lift	Tubing Plungers	4332 Tallmadge Rd.	Rootstown	OH	44272	330-325-1951
Lufkin	Pumping Units	601 S. Raguet	Lufkin	TX	75901	936-634-2211
Midway Supply	Jet Star Casing Plungers	291 Branstetter St.	Wooster	OH	44691	330-264-2131
Moyno	Progressive Cavity Pump	363 N. Sam Houston	Houston	TX	77060	281-445-1545
Multi Products	Tubing and Casing Plungers	PO Box 286	Millersburg	OH	44654	800-777-8617
National Oilwell	Pumps and Units	10000 Richmond	Houston	TX	77042	713-346-7561
Plungerlift Systems	Tubing Plungers	PO Box 9423	Midland	TX	79708	915-699-1200
Production Control	Production Enhancement	1762 Denver Ave.	Fort Lupton	CO	80621	303-659-9322
REDA	Electric Submersible	PO Box 1181	Bartlesville	OK	74005	918-661-2000
Sage Technologies	Fluid Level Equipment	PO Box 1466	Grapevine	TX	76099	877-488-2579
Skillman Pump Co.	Downhole Pumps	211 RR 620 South	Austin	TX	78734	888-826-4082
Weatherford	Most Artificial Lifts	1900 E. 25th Street	Oklahoma City	OK	73129	405-672-0003
Well Master	Plungerlift Systems	12860 W. Cedar Dr.	Lakewood	CO	80228	800-980-0254

Appendix 21
Directory of Stripper Well Resources

Company	Address	City	State	Zip	Phone
American Petroleum Institute	1220 L Street	Washington	DC	20005	202-682-8000
Artificial Lift Energy Optimization Consortium	Texas Tech University	Lubbock	TX	79409	806-842-1801
Artificial Lift R&D Council (ALRC)	2516 Timberline Drive	Austin	TX	78746	513-330-0671
Interstate Oil and Gas Compact Commission	PO Box 53127	Oklahoma City	OK	73152	405-525-3556
Marginal Oil and Gas Well Commission	1218B W. Rock Creek Rd.	Norman	OK	73069	405-366-8688
National Energy Technology Laboratory	PO Box 880	Morgantown	WV	26507	304-285-4589
National Petroleum Technology Organization	1 West 3rd Street	Tulsa	OK	74103	918-699-2076
National Stripper Well Association	10077 Grogan Mill Road	The Woodlands	TX	77380	281-364-7037
PERFORM Research Center	Colorado Sch. of Mines	Golden	CO	80401	303-273-3042
Petroleum Technology Transfer Council	PO Box 246	Tulsa	OK	74063	918-241-5801
Southwestern Petroleum Short Course	Texas Tech University	Lubbock	TX	79409	806-842-1801
Stripper Well Consortium	C-211 Coal Utilization Lab	University Park	PA	16802	814-865-4802
Texas Tech Univ. - PL-OPT/SWPSC	Box 43111	Lubbock	TX	79409	806-742-1727

New Technologies for Lifting Liquids from Natural Gas Wells

during the Period 05/15/2001 to 05/14/2002

By

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Colorado School of Mines

February 2003

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Disclaimer

Abstract

When initially completed, many natural gas wells are capable of lifting liquids to the surface. But, with depletion of the reservoir pressure, there comes a time when liquids can no longer be lifted to the surface and they begin to accumulate in the bottom of the well, dramatically inhibiting or stopping gas production. The cause of diminished liquid-lifting ability is the decline of liquid droplet production at gas flow rates below the Turner-Hubbard-Dukler critical velocity.

In this research, three tasks were planned for developing technologies that enhance droplet production and facilitate lifting at low gas flow rates:

Task 1: Enhancing droplet production. To overcome the limitation of diminished capacity for droplet generation at the low gas velocities of stripper gas wells, develop devices that stimulate droplet production by sonic and ultrasonic means in bench-top and flow-loop tests.

Task 2: Integrated modeling of gas well production. Test and develop a numerical model that combines the complexities of two-phase flow in the wells and the adjacent reservoir with the droplet-stimulation technologies. Use this model to develop plans for field tests.

Task 3: Field testing of new technologies. Test the previously developed tubing-insert technology in a field setting.

Accomplishments for each of these tasks are summarized below.

Task 1: Enhancing droplet production. We expanded the scope of this task to include testing of rotational and two-fluid devices as well as vibrational (sonic and ultrasonic) devices for droplet production. Vibrational and two-fluid devices were obtained from commercial sources; we assembled a rotating device for testing. Bench-top tests showed that all three classes of devices could produce small droplets, but the ultrasonic devices produce the smallest droplets. The rate of conversion of bulk liquid to droplets is highest for the rotational and two-fluid devices.

The three classes of devices were also tested in a flow loop. The flow-loop tests showed that very small droplets (about 3 micron diameter droplets produced with an ultrasonic device) can be transported the height of the loop (10.7 m, or 35 feet) without coalescing on the walls of the tubing. Flow-loop tests with the rotational and two-fluid devices were discouraging. We were unable to produce small droplets with the rotational device in the confines of the 6.35-cm-ID (2.5-inch-ID) of the flow loop. And with the two-fluid device, 50 to 70% of the produced droplets impinged and coalesced on the ID of the flow loop within ten feet of the device. According to specifications for the two-fluid device, the produced droplets should have diameters between 20 and 90 microns.

Heuristics in the literature and conversations with experts on droplet transport led to the expectation that droplets with diameters less than 30 microns could be transported from the bottom of a well to the surface without significant difficulty.

An energy analysis showed that a barrel of water could be converted to 30-micron droplets for less than 30 cents.

Task 2: Integrated modeling of gas well production. We began simulation of the reservoir-well system with Eclipse 100 models. One model showed that incomplete removal of water from the well diminished ultimate gas recovery by about 20%.

Task 3: Field testing of new technologies. Progress on Task 3 was limited to preliminary discussions of suitable wells with operators.

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Description of Approaches

Task I: Enhancing droplet production. This laboratory effort consisted of two parts: bench-top tests, and flow-loop tests. We completed bench-top tests of vibrating, rotating, and two-fluid devices for stimulating droplet production. The goal of these tests was to identify promising approaches for making droplets of the desired size for further testing in the flow loop.

In tests for vibrational devices, a small quantity of water was vibrated with a sonic (less than 20,000 hz) or ultrasonic (greater than 20,000 hz) driver. Finding suitable devices for these tests was a chore. I pursued many leads on the internet and by telephone. In Table 1, I list the commercial sources of ultrasonic devices that were contacted. The vibrational drivers that were selected for testing consisted of a vibrational transducer that is available in the Mining Department at CSM, and piezo devices obtained from Radio Shack and APC International. The vibrational transducer in the Mining Department was suited for tests up to about 400 hz. The piezo device from Radio Shack operates at 3,000 hz and requires a 9-volt battery. APC International provides a wide variety of piezo devices, including bending disks with optimum frequencies up to about 10,000 hz, air transducers that operate at 24,000 and 42,000 hz, and ultrasonic humidification devices that operate at 1.6 Mhz. For testing of the sub-50,000 hz APC International devices, a frequency generator and an amplifier were used for providing the needed electrical excitation. The 1.6 Mhz device requires 48-volt AC power, which was provided by a variable voltage transformer. For droplet production tests at frequencies up to 3,000 hz, we measured the diameter of droplets from digital images.

Table 1. Commercial Sources of Ultrasonic Devices.

Company	Contacts	Products
APC International (americanpiezo.com)	Rich Brooks 570-726-6961	Distributes a variety of ultrasonic products – including the same transducer that DGH offers – but the APC price is about $14!
Branson	Jeff Hilgert 203-796-0461	Ultrasonic cleaners that operate at 20 to 40 kHz
Clomatic Corp	B. Y. Chen (clco5046@ms14.hinet.net)	Makes the transducer that is distributed by DGH Systems
DGH Systems	Scott Herr 717-293-5210	Distributes a low-cost ($40) transducer for humidification
Electrowave (electrowave.com)	Gary Lewis 715-426-7378 Mark Sellins 858-695-2227	Website speaks effusively about high power transducers that they make – rather than distribute for someone else.
Etrema	Tim Drake 816-246-0566 Duane Canny 515-296-8030	Makes some vibrational devices for down-hole seizmic stimulation. Specialize in magneto-strictive devices that usually operate at less than 20,000 hz.
Sono-Tek (sono-tek.com)	Dean Calamaras	Nozzles with frequencies from 25 to 120 kHz, and flow rates from 1 to 6 gal/hr

	845-795-2020 x127	
Sonics & Materials (sonicsandmaterials.com)	Ed Neeb 203-270-4600 x316 Mike Donatti	A competitor of Sono-Tek with roughly equivalent products at about half the price. Working on some down-hole devices for an undisclosed application.
Stulz (stulz-ats.com)		Use TDK transducers in products for humidification.
TDK (www.tdk.co.jp/tefe02/ef441_nb.pdf)		Piezo transducers: NB-514S-01-0, and NB-59S-09S-0 (These are very similar to those available from APC and DGH, but their cost is $50 to $100.) Magneto-strictive transducers: V2X series

We tested two different types of rotational devices: a Dremel tool with a 1-inch-diameter cutting disk attached, and a child's siren whistle. For tests with the Dremel tool, a stream of water was directed at the rapidly spinning cutting disk; for tests with the siren whistle, water was blown through the whistle with compressed air.

For tests of two-fluid nozzles, I first located liquid nebulizers that are used in the medical field for inhalation therapy (Hudson RCI No. 1882 Micro Mist Nebulizer; Omron No. 9911 AIRS Nebulizer). These nebulizers consist of small cups (about 5 ml capacity) concentrically mounted on an air nozzle. The liquid is sucked into the orifice region of the air nozzle where it breaks into small drops. An air supply of about 1 scf per minute is needed for the nebulizers. A large capacity two-fluid nozzle was purchased (Sonimist Model 900-2 from Misonix). Operation of this nozzle requires a gas stream of 15 to 20 SCF per minute combined with injection of bulk liquid at a variety of rates.

In addition to bench-top tests of droplet production, we conducted flow-loop tests to study the transport of droplets. The flow-loop lay-out is shown in Figure 1. A key feature of the flow loop is the droplet generator, which was adapted to each approach used to produce droplets. For tests with ultrasonic devices (just the 1.6 MHz ultrasonic transducers were tested in the flow loop), the configuration in Figure 2 was used. The ultrasonic device was located at the bottom of the flow loop in a shallow pool of water. For tests with the rotational devices (the Dremel tool), the configuration of Figure 3 was used. The rotational device was located 2 to 3 feet from the bottom of the flow loop; water was blown onto this device by the flowing air as it agitated a shallow pool of water at the bottom of the flow loop. In tests with two-fluid devices, two configurations for the droplet generator were used. The approach for tests with the medical nebulizers is shown in Figure 4. As in tests with the rotational device, water was blown onto the nebulizer cup from a shallow pool of water at the bottom of the flow loop while a small stream of air was injected to the cup to nebulize the water. In tests with the two-fluid nozzle from Misonix, water and air were injected to the nozzle as shown in Figure 5. In all tests, we detected transport of droplets by scattering of light from the He-Ne laser beam and by collection of water in the gas-liquid cyclone separator.

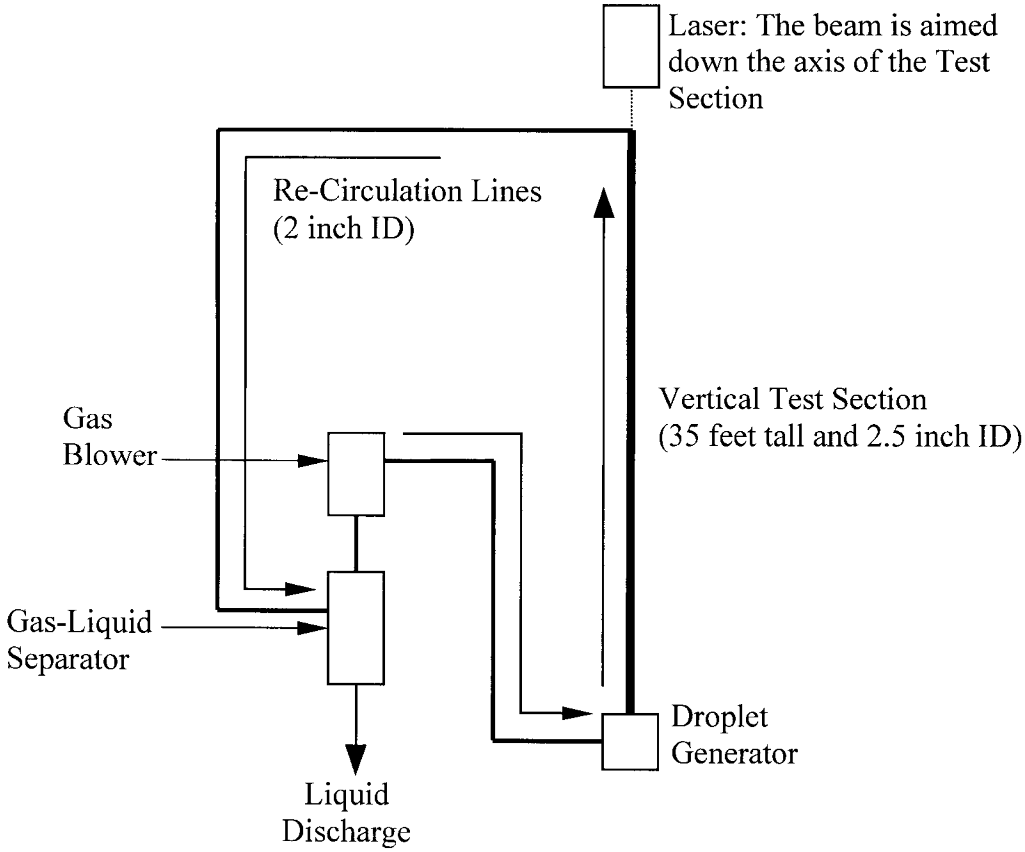

Figure 1. Schematic of Flow Loop.

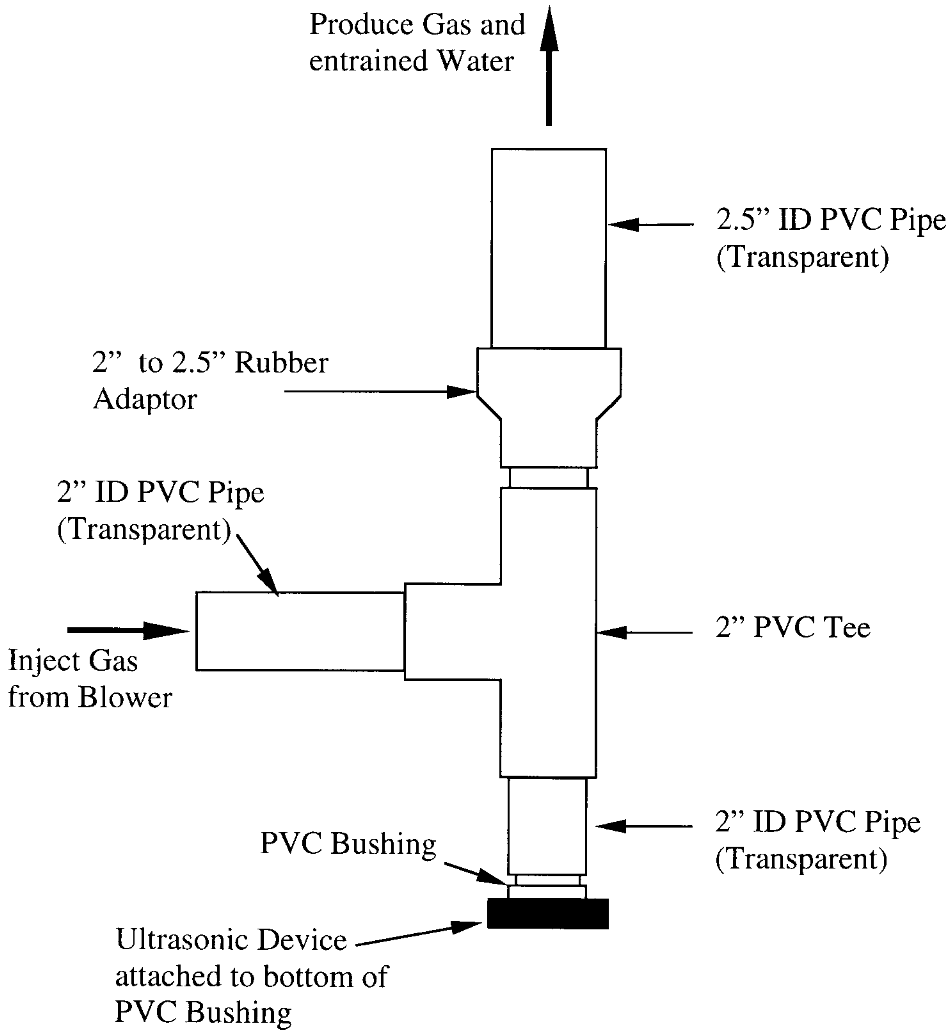

Figure 2. Schematic of the Droplet Generator for Tests with Ultrasonic Device.

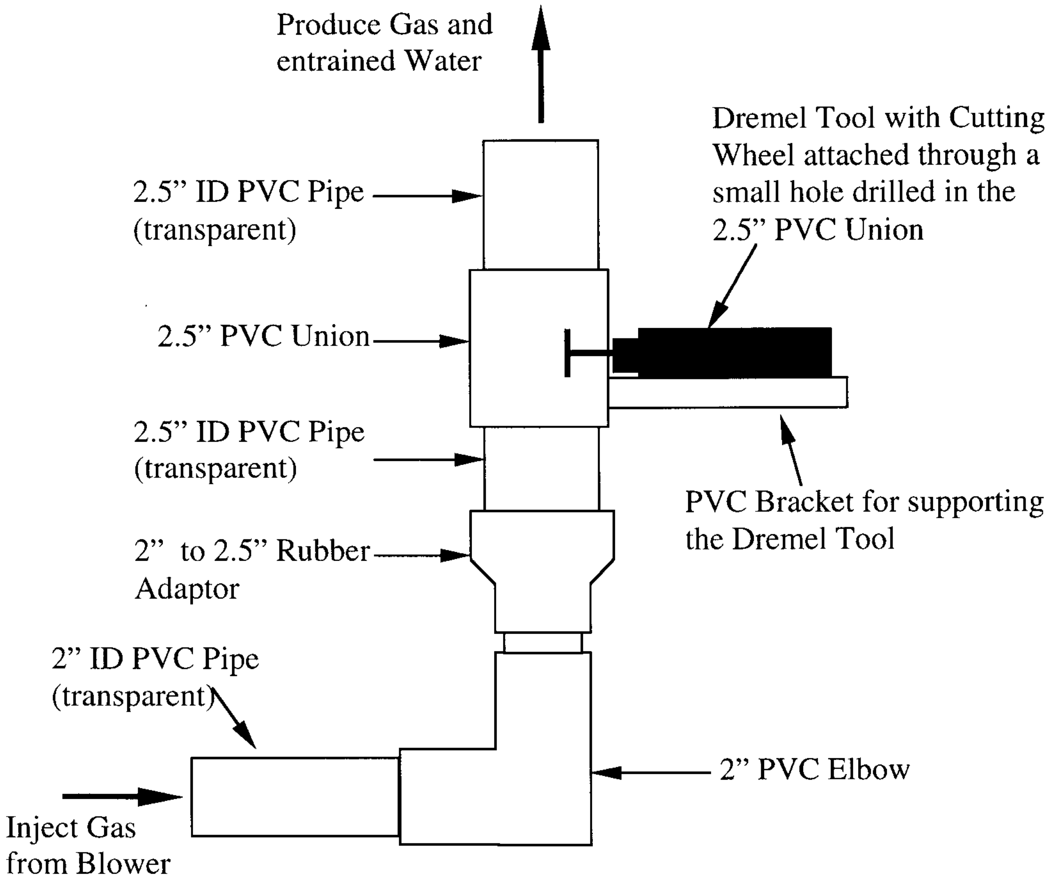

Figure 3. Schematic of the Droplet Generator for Tests with the Rotational Device.

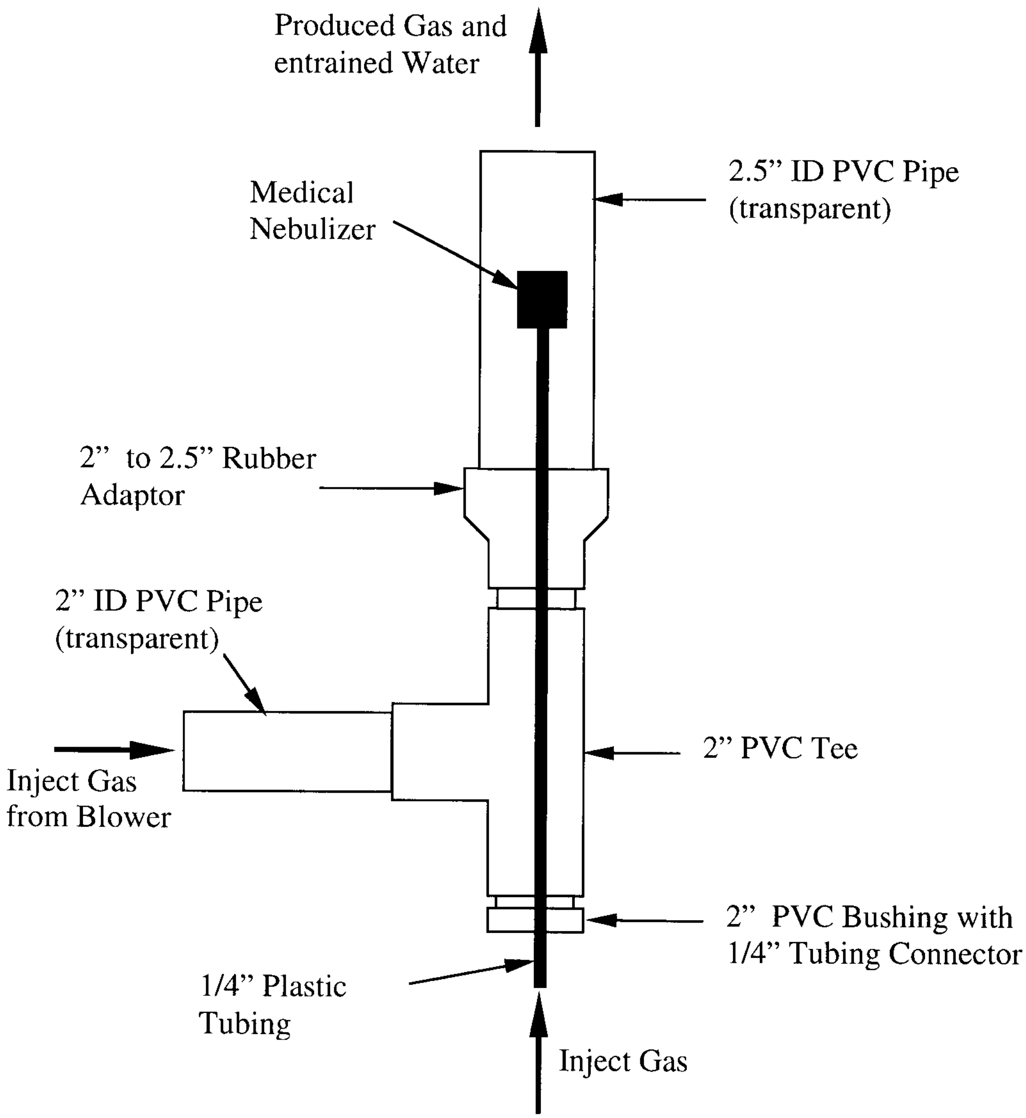

Figure 4. Schematic of the Droplet Generator for Tests with the Medical Nebulizer.

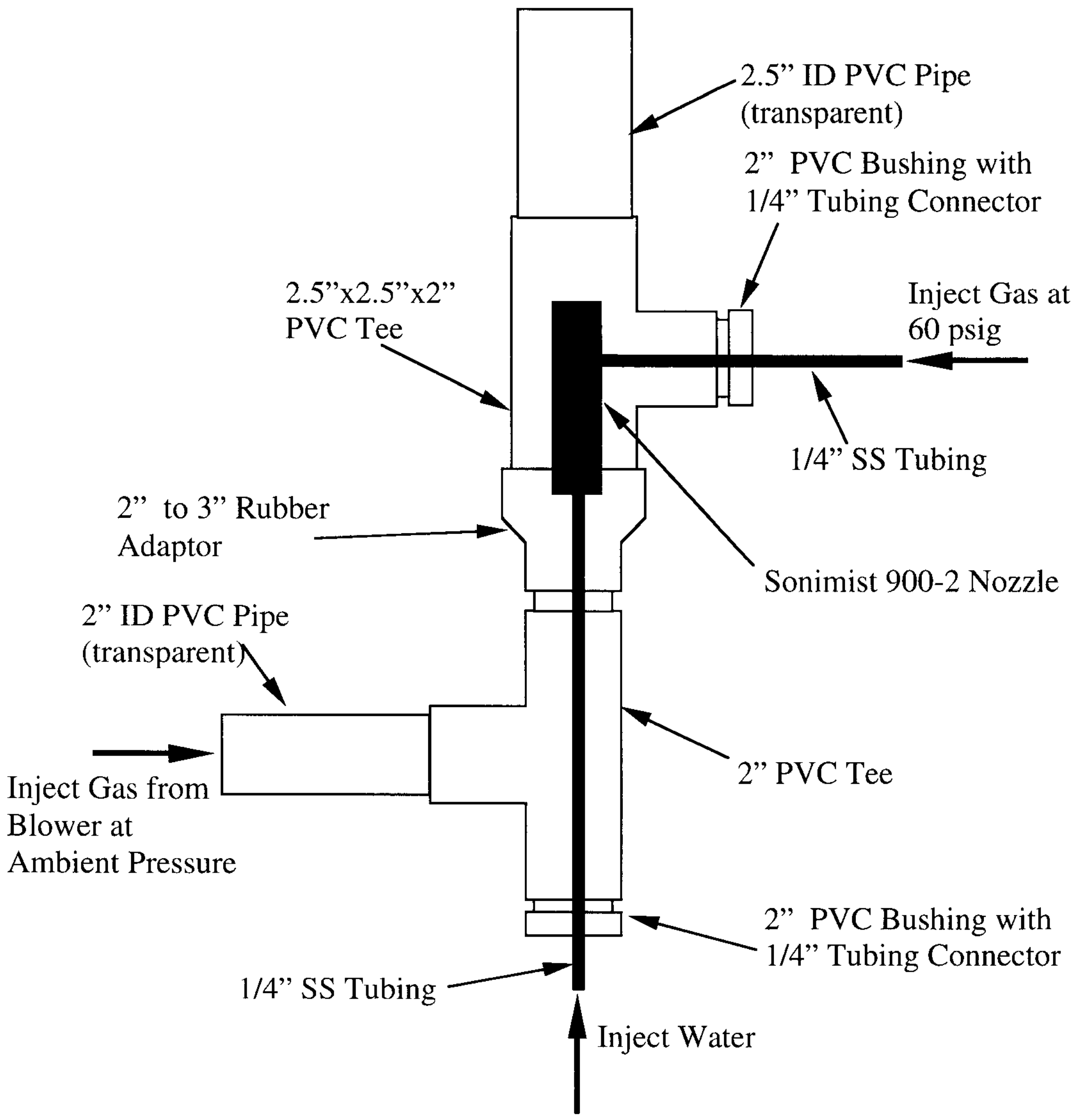

Figure 5. Schematic of the Droplet Generator for Tests with the Misonix Sonimist Nozzle (Model 900-2).

Task II: Integrated modeling of gas well production. In this task, we attempted to model the combined system that consists of the reservoir and the well. We hoped that this effort would increase our ability to plan and interpret field tests of lifting technology, as well as our understanding of the benefits of effective liquid lifting. Although we did not complete an integrated model, we did investigate separately the reservoir and well-bore issues with modeling. We developed several models of gas reservoirs using Eclipse 100. Again, these single-well models were not integrated models – they are just reservoir models. However, we adjusted the operation of the well to reflect problems that occur in gas reservoirs. Specifically, we converted the well from a gas producer to a water injector at regular time interval to simulate cessation of gas production and the consequent imbibition of water that should have accumulated in the well-bore. The amount of injected water is small – less than 10 barrels. Such small amounts of water could accumulate in the production tubing during normal gas production; when production ceases, it would fall to the bottom of the well where it can be imbibed by the producing formation.

I also wrote well-bore models in Excel Visual Basic using the Gray model and the Duns and Ros model as described by Brill and Mukherjee(1999). These models were used mostly to investigate operating conditions in wells that were considered in Task III.

Task III: Field testing of new technologies. For this task, I contacted a few producers with the hope of identifying wells for testing of the tubing-insert technology that we developed previously [Yamamoto and Christiansen (1999)]. A previous study [Putra (2000)] suggested the slug-flow regime was most suited for successful application of the tubing-inserts. Hence, after discussions with producers, I used the flow models from Task II to assess the flow conditions, including flow regimes, in the wells.

Results and Discussion

Task I: Enhancing droplet production. This section begins with discussion of the context of the problem of liquid lifting, continues with results of our research, and ends with discussion of feasible approaches for application of the results.

The root of the liquid-lifting problem in gas wells is droplet size. At high gas flow rates, liquids break into droplets of sufficiently small size for lifting by the gas. With decreasing gas flow rate, both the droplet creating capacity and the droplet lifting capacity decrease. This idea was succinctly represented by Turner, Hubbard, and Dukler (1969) in their expression for critical gas velocity v_c – the minimum velocity for dispersing and lifting liquid as droplets:

$$v_c = 0.567\left[\frac{(\rho_l - \rho_g)\sigma_{gl}}{\rho_g{}^2}\right]^{1/4} \qquad 1$$

Here, the critical velocity has units of ft/sec, the liquid density ρ_l and the gas density ρ_g have units of g/cm^3, the gas-liquid interfacial tension σ_{lg} has units of dyne/cm. If the velocity of gas declines below v_c, then liquid accumulation begins. For a natural gas-water system at 311 K and 689 kPa (100°F and 100 psia), the critical velocity is about 6.7 m/sec (22 ft/sec).

In this research, we sought ways to stimulate production of droplets that can be lifted by velocities less than the critical velocity of Eq. 1. To understand the target better, let's estimate the size of droplets at the critical velocity using the critical Weber number:

$$N_{We,c} = \frac{\rho_g d v_c{}^2}{\sigma_{gl}} \qquad 2$$

Turner *et al.* used 30 for the value of the critical Weber number; however, a range of 10 to 30 might be more appropriate. Then, the range of average diameter of droplets at the critical velocity can be estimated from Eq. 2:

$$10\frac{\sigma_{gl}}{\rho_g v_c^{\,2}} < d < 30\frac{\sigma_{gl}}{\rho_g v_c^{\,2}} \qquad 3$$

For the gas-water system at 311 K and 689 kPa (100°F and 100 psia), the effective diameter *d* is between 3 and 8 mm.

To produce smaller droplets that will provide for liquid lifting at lower gas flow rates, we investigated three approaches for droplet production: vibrational, rotational, and two-fluid flow. There are correlations in the literature for estimating the size of droplets produced with each of these approaches [Bayvel and Orzechowski(1993), Liu(2000), and Masters(1979)]. Here, we focus on a correlation for the vibrational approach because it showed the most promise for future development – and because it is the easiest to understand and use. According to Lang(1962), the size of droplets produced by sound can be estimated with the following expression:

$$d = 0.34\left(\frac{8\pi\sigma_{gl}}{\rho_l f^2}\right)^{1/3} \qquad 4$$

In this expression, *d* is the droplet diameter(m or cm), σ_{gl} is the gas-liquid interfacial tension(mN/m or dyne/cm), ρ_l is the density of the liquid(kg/ cm^3 or g/cm^3), and *f* is the sound frequency (Hz or cycles per second). Lang based the correlation of Eq. 4 on measurements at frequencies of 7,000 to 1,000,000 Hz.

During the second quarter of this project, we measured the size of droplets produced in vibrational tests for frequencies from 25 to 3000 Hz. Digital images of droplets formed in tests with the vibrational transducer in the Mining Department are shown in Figures 6 to 9. In these tests, a shallow pool of water in a plastic cup was attached to the top of the transducer. Sizes of several droplets from each image were measured and averaged. The results of these measurements are predicted quantitatively by extending the Lang correlation to low frequencies as shown in Figure 10. The trend of decreasing droplet size with increasing frequency is easily seen in these figures.

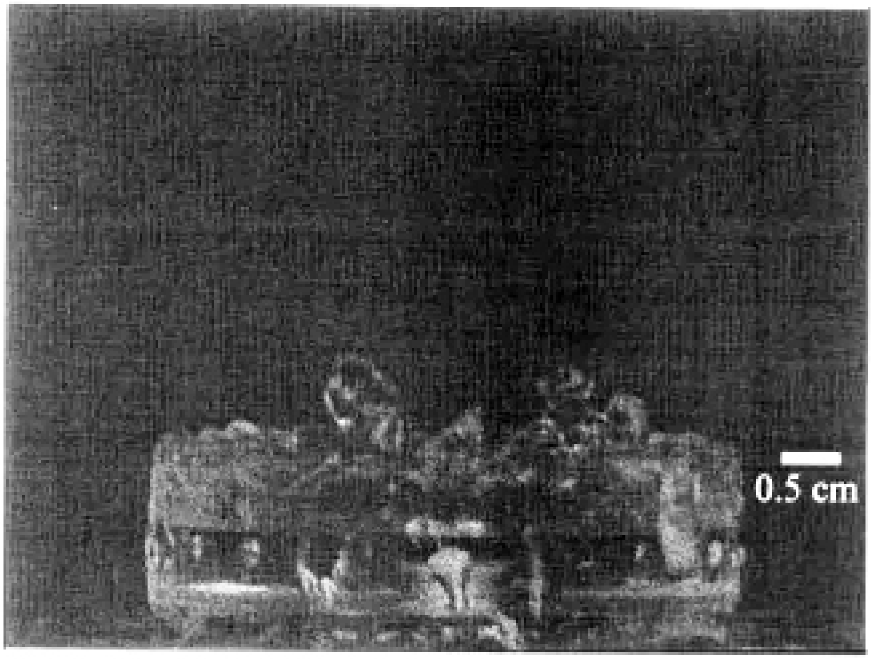

Figure 6. Droplet formation at 25 hz.

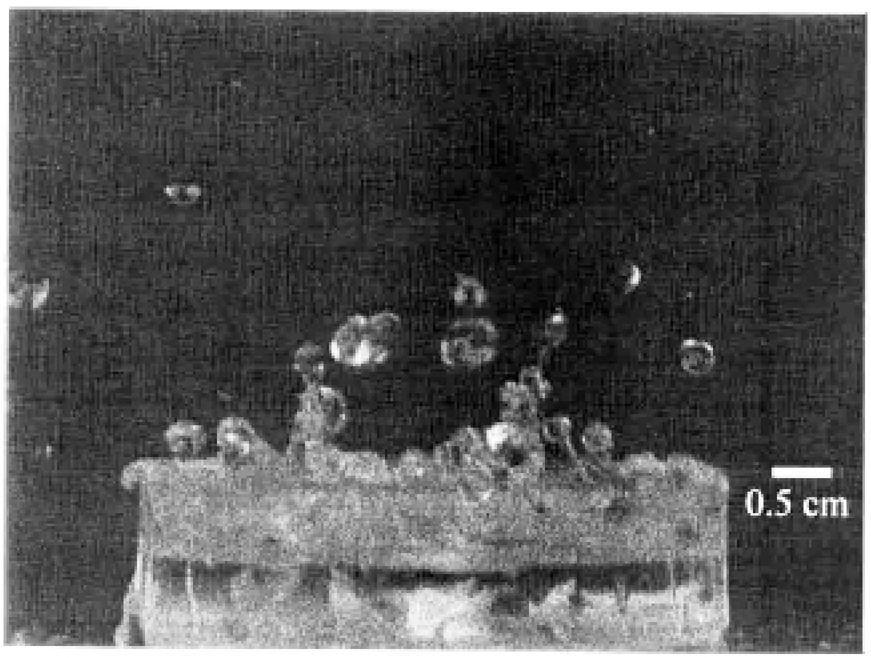

Figure 7. Droplet formation at 50 hz.

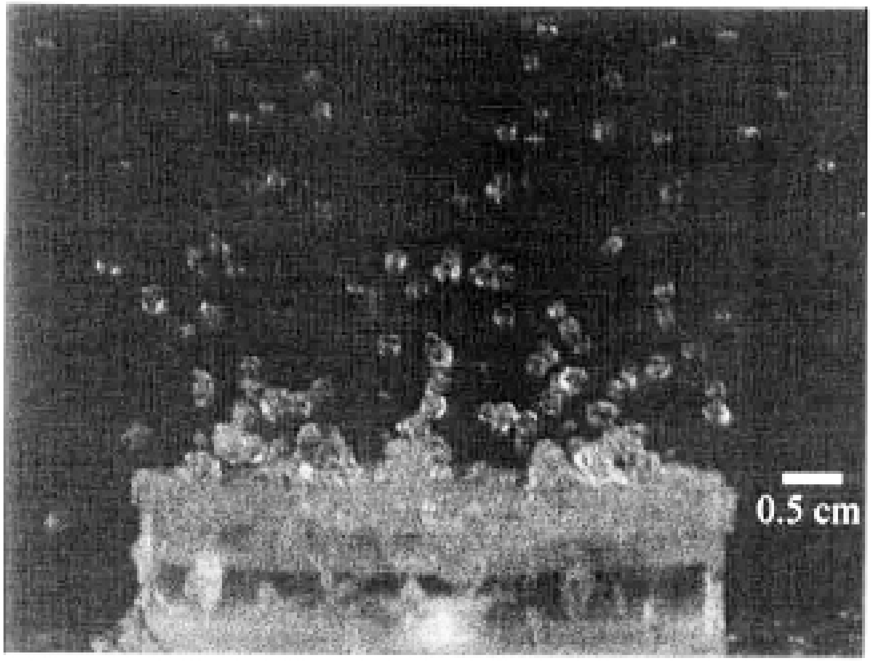

Figure 8. Droplet formation at 100 hz.

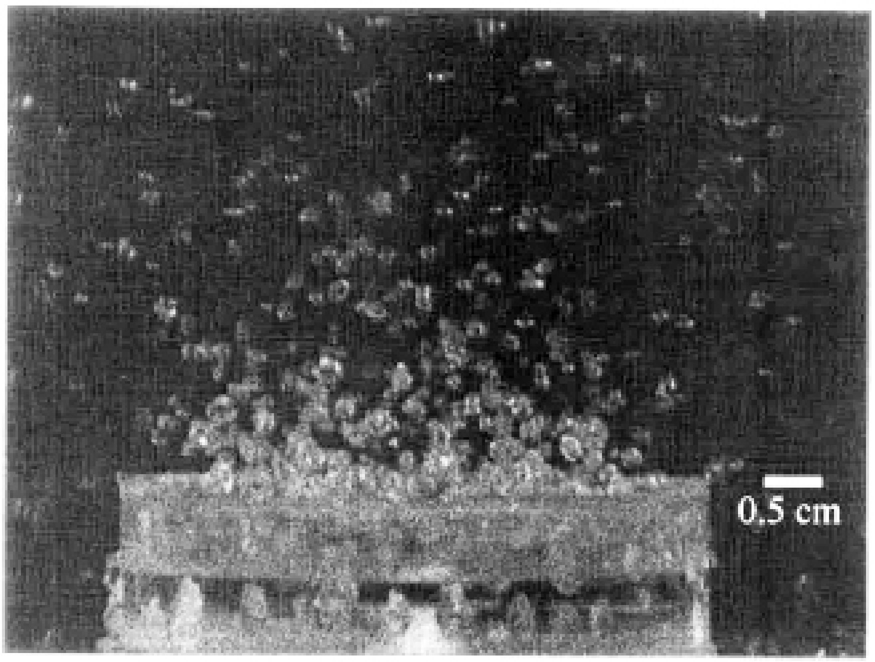

Figure 9. Droplet formation at 200 hz.

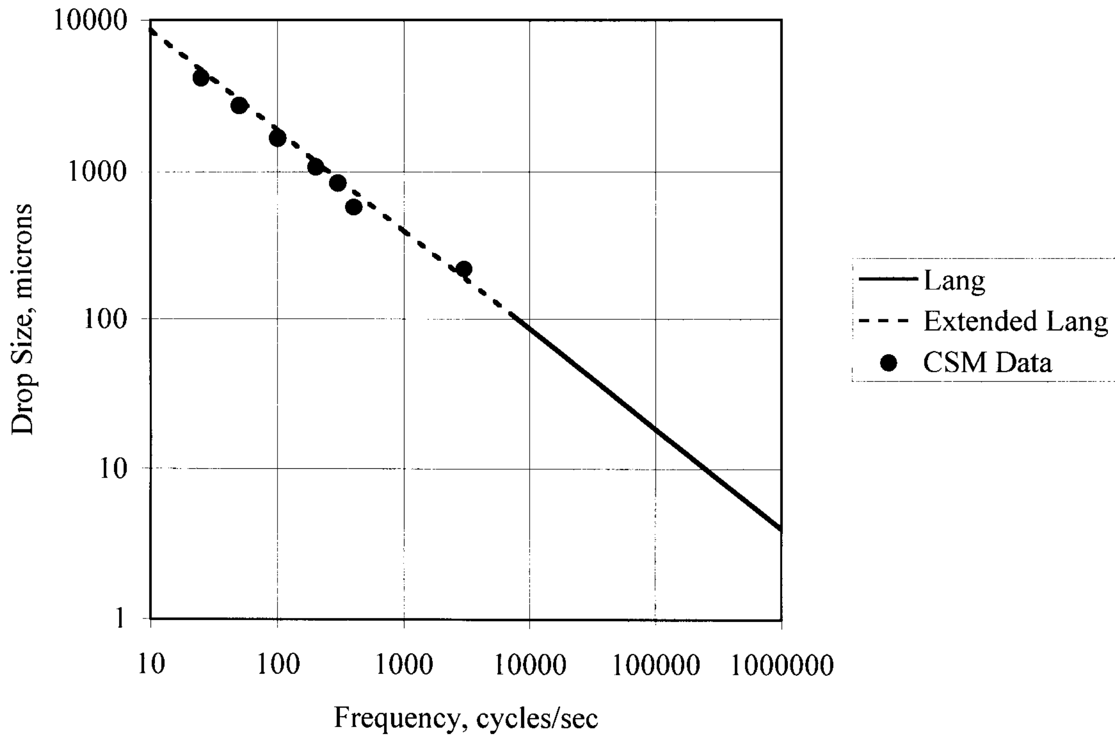

Figure 10. Extrapolating Lang's correlation to low frequencies quantitatively predicts our bench-top measurements.

The size of droplets produced by rotational devices decrease with speed of rotation and with diameter of the spinning wheel from which the liquid is released. Rotational devices are used in many spray-drying applications. In these applications the spinning wheel may be 6 to 10 inches in diameter. And the spray from the spinning wheel typically extends for many diameters beyond the wheel. Such dimensions are not suited to bottom-hole application where inside diameters of tubing and casing are generally less than 3 and 6 inches respectively. Our observations for 1-inch-diameter cutting wheels on Dremel tools spinning at 10,000 to 20,000 rpm conform to the descriptions in spray-drying texts [Masters, 1979]. The spray from the wheel extended 10 to 12 inches away from the wheel, and droplets of a wide size distribution were produced – we did not quantify the size distribution.

The size of droplets produced with two-fluid nozzles decreases with increasing gas flow rate and with decreasing liquid flow rate. With medical nebulizers, droplets with diameters less than 10 microns are produced for inhalation therapy. In these applications, just small quantities of liquid medication are applied at a low rate, usually just a few milli-liters per hour. Larger two-fluid nozzles are capable of much higher liquid rates – equivalent to ten or more barrels per day. (1 barrel per day is about the same as 100 ml per minute.) The dimensions of two-fluid nozzles and the associated plume of droplets are more compatible with bottom-hole dimensions than rotating devices. In bench-top tests with medical nebulizers the plumes were generally less than 2 inches in diameter after travel 3 feet from the nozzle. For the Misonix Sonimist two-fluid nozzle, the plume expanded to about 6 inches after traveling 3 feet from the nozzle. Droplet sizes for the Sonimist 900-2 nozzle are not available from Misonix. Data for the Sonimist 900-4 nozzle show droplet sizes in the 20 to 90 micron range.

Our bench-top tests and the literature convinced us that droplets of any desired size for liquid lifting can be produced with the appropriate choice of approach and operating conditions. After reaching this conclusion, we needed to answer the next big question: How far can we transport the droplets produced by one of these approaches in a well-bore? Answers to this question were obtained from flow-loop tests, from the literature, and from discussions with experts.

For flow-loop tests on the vibration approach for droplet production, we chose to use the ultrasonic transducer that operates at 1.6 Mhz. As described previously, this device was attached to the bottom of the flow loop with the face of the piezo disk at the bottom of a 1 to 2-inch-deep pool of water. When operating, the device should provide droplets with average diameter of about 3 microns at a liquid rate of 500 cm^3 per hour. Lifting of the 3-micron droplets to the top of the loop was readily observed by scattering of the laser beam by the droplets. Even with the flow rate at zero, the droplets remain suspended in the loop for more than 10 minutes. These results are very satisfying, probably even better than is needed in field applications. It is expected that the liquid-flow rate-capacity of ultrasonic devices increases with decreasing frequency. So devices operating at 100,000 hz that produce droplets in the 10 to 20 micron range might be very satisfactory. Such devices are commercially available, but they are much more expensive than the 1.6 Mhz transducer. Design of ultrasonic devices for specific application to gas wells is an issue that should be explored, but it is beyond the scope of this project.

Flow-loop tests with a rotational device (a Dremel tool with a 1-inch-diameter cut-off wheel) and with a two-fluid nozzle (medical nebulizers) were discouraging. In these tests, the device was located about 3 feet above the bottom of the flow loop. Water from the bottom of the flow loop was entrained in the flowing gas stream and carried to the vicinity of the generators. We were unable to detect any increase in liquid lifting due to the action of the generators. In the case of the rotational device, we hypothesize that the water is not being directed very effectively at the cutting wheel; as a result, the quantity of produced droplets is small. Furthermore, most if not all of the produced droplets probably impinge on the inside wall of the tubing.

For the two-fluid category of approaches to droplet production, we tested both the medical nebulizers and the Misonix Sonimist 900-2 nozzle in the flow loop. Results with the medical nebulizers were no better than the results for the rotational device described above. For the Misonix nozzle, the results were much more encouraging. Approximately one-third of the water injected to the nozzle was carried to the top of the 35-foot-tall flow loop and then to the liquid collection point shown in Figure 1. This result is consistent with the heuristics for lifting droplets of different sizes. It is suggested in the following paragraph that droplets larger than 30 microns are difficult to transport. I expect that a large portion of the droplets produced by the Sonimist nozzle are larger than 30 microns.

During the second quarter of this project, we found some insight for droplet transport in the literature on separation of suspended liquids from gas streams, as summarized by Fair *et al.* Figure 11 (Figure 18-133 of Fair *et al.*) shows typical classifications and separation equipment for separating particles from gases. We expect that the size range of most interest for the current research is 10 to 1000 microns. Particles with diameters of 1000 microns are quite easily removed from gases by gravitational settling. But in the range of 10 to 100 microns, more "aggressive" methods are needed, such as centrifugal separators or mist eliminators (impingement separators). By crude analogy, we expect that droplets in the 10 to 100 micron range will be more easily transported in the wells than the larger droplets. In the third quarter, I located Dr. Chien Pei Mao of Delavan Corporation who is an expert on droplet transport. He advised that droplets with diameters less than 30 microns are easily transported.

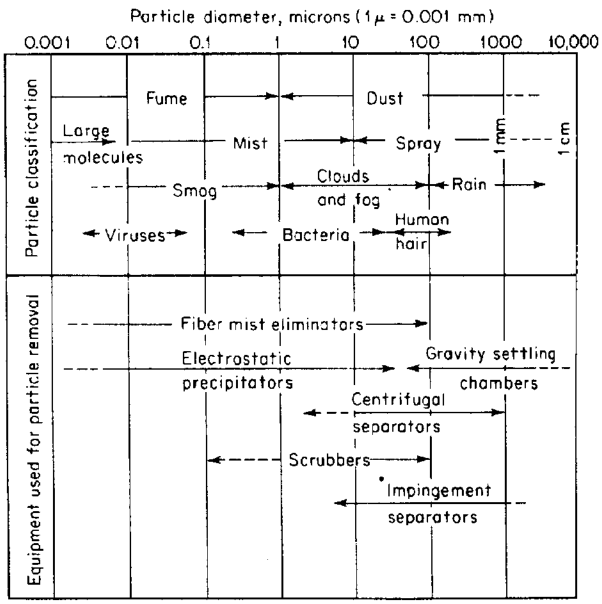

Figure 11. Particle nomenclature and separation schemes from Fair *et al.*

Another issue that we have addressed during this project is the cost of droplet production. Table 2 summarizes a theoretical analysis of the amount of energy needed to convert one barrel of water into 30-micron droplets. In the table, the volume and surface area of each droplet is first calculated. Next, the number of droplets with total volume of one barrel and their cumulative surface area is calculated. Finally, based on the surface energy per unit area of water, the required energy to make the droplets is obtained. (Surface area per unit area is equivalent to surface tension.) The end results, 2.11 Btu or 0.00062 kw-hr, is extraordinarily small. However, we have found in tests and the literature [Fair et al., 1973] that the actual energy requirement for droplet production is 1,000 to 10,000 times greater than the theoretical estimate of Table 2. Droplet production is surprisingly inefficient! Multiplying the theoretical requirement by 1,000, the required amount of energy is 0.62 kw-hr, which is equivalent to 3 cents if electrical power costs 5 cents per kw-hr. Using a multiplier of 10,000, the corresponding energy cost is 30 cents. The cost for making droplets should depend on the method used to make the droplets, whether vibrational, rotational, or two-fluid. But I have little additional information for distinguishing costs for the three approaches. For two-fluid nozzles, the estimated energy cost is about 90 cents per barrel based on operating dating from the catalog of Spraying Systems, Inc. This result for two-fluid nozzles is surprising because I had understood that two-fluid nozzles should be more efficient than other approaches.

Table 2. Energy Analysis for Droplet Production

30	Diameter, microns
1.41E-08	Volume of droplet, cm3
2.83E-05	Area of droplet, cm2
1.12E+13	Droplets per barrel
3.18E+08	Area of droplets per barrel, cm2
70	Surface energy for water, erg/cm2
2.23E+10	Energy, erg
2.11	Energy, btu
0.00062	Energy, kw-hr

Considering all of the above results, we have reached some useful conclusions for field application of droplet enhancing technologies. First, it is very unlikely that rotational devices can perform suitably for field application. Second, although two-fluid devices show more promise than rotational devices, we have not found a two-fluid device that is good enough for field testing – perhaps future studies will reveal a better two-fluid device. Third, vibrational devices do show some promise for successful field application. For vibrational devices, we suggest two alternative approaches for field testing:

1. Install the 1.6 Mhz transducers that are available from APC International in multiple tubing joints. These transducers cost about $15 each. Each transducer is capable of processing about 500 ml/hr to droplets between 1 and 5 microns. With 20 of the transducers installed at tubing joints, the total liquid capacity would be between 1 and 2 bbl/day. The devices require a 48-volt AC power supply.

2. Install one of the ultrasonic nozzles produced by Sono-Tek or Sonics & Materials. These nozzles are capable of processing up to 5 gal/hr (about 3 bbl/day), depending on the desired droplet size. The cost of a single Sono-Tek nozzle is $2500 plus $3500 for a power supply (quantity discounts are available). A higher capacity nozzle may be available later this year from Sono-Tek. Comparable nozzles from Sonics & Materials cost between $2000 and $3000.

The two approaches provide hope for a successful (technically and economically) field test.

Task II: Integrated modeling of gas well production. For this task, I hoped to combine a model of reservoir behavior with a model of well-bore behavior. While this may be possible, I was not able to accomplish it within the time frame of this project. I was able, however, to complete some analysis of the two separate problems.

First, we wrote Eclipse 100 models to simulate the effects of water accumulation on gas production. One of the Eclipse 100 models is a radial model with horizontal permeability of 10 md, and vertical permeability of 1 md. The model is 60 feet thick. Cumulative production and production rate are shown in Figures 12 and 13 for a period of about 2200 days. Figure 12 shows that the cumulative production for periodic shut-in with re-injection of a small amount of water is about 20% less than that for continuous production of gas. Figure 13 shows the corresponding variations in gas production rate. After injecting water during the shut-in period, the gas production rate slowly rises toward the rate that is found for the continuous production model. Clearly, water that is not removed from the well has a significant detrimental effect on ultimate gas recovery.

Second, I wrote Excel Visual Basic modules for well-bore simulation with the Gray model and the Duns and Ros model for two-phase vertical flow. I tested these models against performance in our flow loop. These models provided a lot of insight for interpretation of well-bore behavior, but there is much room for improvement. For example, many engineers in the industry maintain that a modified Hagedorn-Brown model is best for representing well-bore behavior. Other engineers favor mechanistic models. I used the Gray model primarily because it was very easy to write. I chose the Duns-Ros model because of its foundation in laboratory data and because it provides a fairly comprehensive capability for well-bore modeling – it can represent bubble flow, slug flow, the transition from slug flow to annular mist flow, and annular mist flow regimes.

Task III: Field testing of new technologies. For this task, the desire was to find some wells in which we could test the tubing-insert technology that we developed previously [Yamamoto and Christiansen (1999)]. Expecting that the slug-flow regime was most suited for successful application of the tubing-inserts[Putra (2000)], we used flow modeling software (developed in Task II) to assess the dominant flow regimes in wells suggested by various producers. Hence, after discussions with producers, I used the flow models from Task II to assess the flow conditions, including flow regimes, in the wells. Many of the wells that were offered were not dominated by the slug-flow regime. Hence there was little opportunity for pursuing this Task.

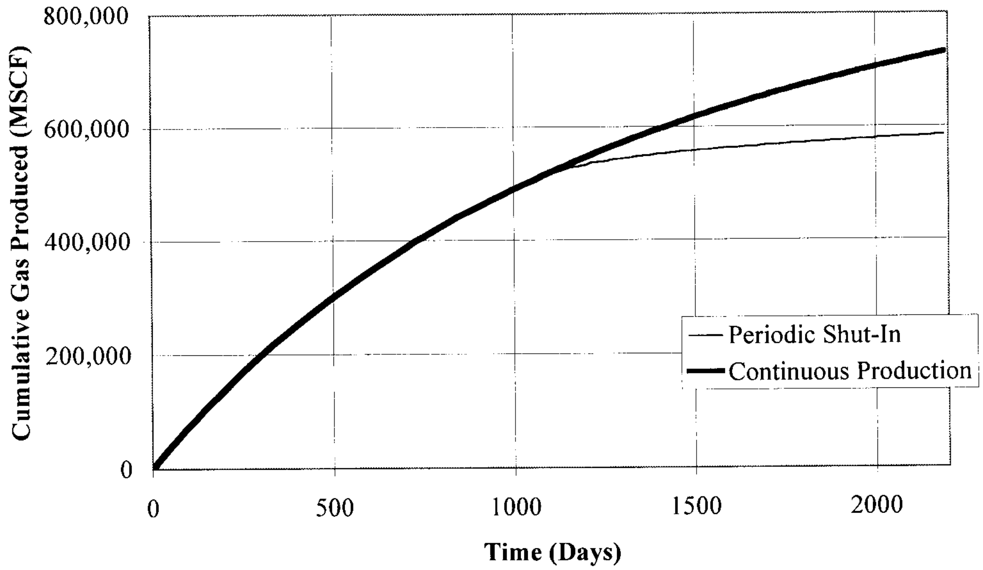

Figure 12. Cumulative production history for continuous production and for production with intermittent shut-in with water injection.

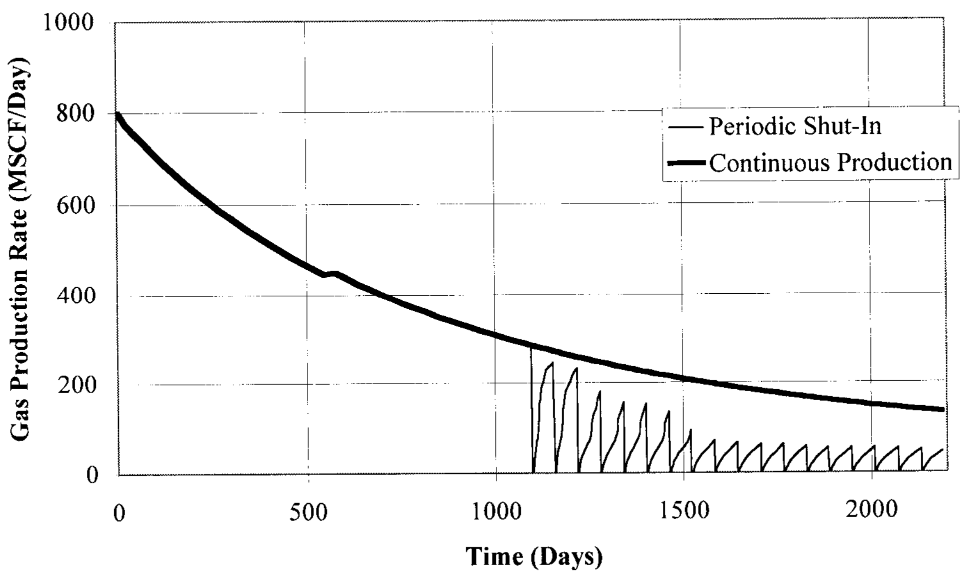

Figure 13. Production-rate history for continuous production and for production with intermittent shut-in with water injection.

Conclusions

1. Droplets in gas wells at the critical gas velocity have maximum equivalent diameters of 3 to 8 mm according to analysis that is consistent with the model proposed by Turner *et al.*(1969).
2. Bench-top tests and analysis show that production of small droplets is possible with vibrational, rotational, and two-fluid devices. The Lang(1962) correlation quantitatively predicts the average size of droplets produced by vibrational means for frequencies from 20 Hz to 1 MHz.
3. Flow loop tests with 1.6 MHz ultrasonic transducers showed that 3-micron droplets can be transported a long vertical distance. Literature on separating liquid droplets from gas streams support this observation. We expect that droplets up to 30-microns can be transported to the surface. Flow loop tests with rotational devices failed completely. Flow loop tests with two-fluid devices were moderately successful.
4. The estimated energy costs of droplet production are low per stage: 3 to 30 cents/bbl for production of 30-micron droplets. If the droplets are less than 30 microns in diameter, just one stage may be sufficient. For larger droplets, multiple stages will be needed in a typical gas well.
5. Feasible approaches for application of vibrational droplet generators have been developed.
6. Simulation results show that production from gas reservoirs can be significantly diminished by incomplete removal of water.

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Optimization of Plunger Lift Performance in Stripper Gas Wells

during the Period 05/15/2001 to 11/30/2002

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DISCLAIMER

ABSTRACT

In this project, an algorithm has been developed and tested to optimize the production and shut-in periods of plunger-lift operation based on reservoir performance. The objective of the optimization is to maximize gas production with the condition that the liquid loaded during production can be lifted to surface by the pressure that builds up during the following shut-in period. The optimization of the production and shut-in periods simultaneously requires an iterative procedure. One of the advantages of the proposed optimization method is the ability to automatically adjust to the changes in the line pressure.

The optimization algorithm combines the conventional plunger-lift theory with an analytical description of the reservoir performance. The conventional plunger-lift theory is used to determine the pressures required for lifting the plunger with a liquid column over it. The production and shut-in times are determined in an iterative manner by using an analytical reservoir model to simulate the reservoir performance.

To implement the algorithm, a relatively simple electronic control system has been designed and manufactured. The cost of the control system is under $1,000 and may be connected to the existing wellhead controls with minimal modification. Using computer simulations, the method has been tested with the field data and indicated that up to 100% increase in the cumulative production may be achieved by optimizing the production and shut-in periods based on the reservoir performance. Three field application tests failed because of what appeared to be power supply related problems. Field testing will resume with stricter regulations on power supply when the winter conditions at the test-well site improve.

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EXECUTIVE SUMMARY

Plunger lift is one of the viable options to produce low volume, stripper gas wells. The efficiency of the plunger-lift production, however, strongly depends on the regulation of the production and shut-in periods. Various techniques have been developed to determine the durations of the production and shut-in periods but they do not use the reservoir performance as their bases. The objective of this project was to develop an algorithm that could optimize the production and shut-in periods of plunger-lift operation based on reservoir performance.

The optimization algorithm uses an iterative approach to determine the production and shut-in periods. The shut-in period depends on how much liquid builds up in the wellbore during the production period and is desired to be minimum. The production period, on the other hand, should be maximized with the requirement that the reservoir be able to build the pressure during the following shut-in period to the level required to lift the produced liquid. The optimization algorithm uses the conventional plunger-lift theory to determine the pressures required for lifting the plunger with the liquid column over it. The production and shut-in times are determined by using an analytical reservoir model in an iterative manner.

The optimization algorithm developed in this project has been tested with the field data in computer simulations. The results indicate that up to 100% increase in the cumulative production may be achieved by optimizing the production and shut-in periods considering the reservoir performance. One of the important advantages of the proposed algorithm is the ability to automatically adjust to the changes in the line pressure. The implementation of the algorithm requires a relatively simple electronic control system that may be built under $1,000 and can be connected to the existing wellhead controls with minimal modification. Three application tests in the field became unsuccessful with technical problems that do not seem to be related to the optimization algorithm and electronic control system developed in this project. Further testing are planned under improved technical conditions when the weather conditions permit.

INTRODUCTION

Low volume stripper wells account for 8 % of the natural gas production in the United States. A stripper well is defined as a well that produces 60 MSCFD of natural gas or less. As the price of gas and oil declines, many of these wells are abandoned because the production and maintenance costs are higher than the selling price. To improve the profitability of these wells, the production needs to be optimized. One of the problems faced by these wells is the production of liquid. Stripper gas wells are loaded periodically with liquid (either condensate or water) and has to be unloaded before the production can begin again. One common solution to unload is the use of plunger lift. The efficiency of production with plunger lift, however, depends strongly on the durations of the production and shut-in periods.

During the shut-in period of plunger-lift production, the plunger sits at the bottom of the tubing with a liquid column resting above it (Fig. 1). The well is shut in for a period until the casing pressure is high enough to lift the plunger. The plunger is lifted with high-pressure gas and, along with liquid, gas is produced until the gas flow rate starts decreasing again. During the production, liquid will continue to load in the well. The well is shut in again, the plunger will drop at the bottom, and the cycle will continue. The plunger has a one way valve in the middle so that the liquid can move through it while the plunger is dropping, but liquid cannot drop while the plunger is lifted to the surface.

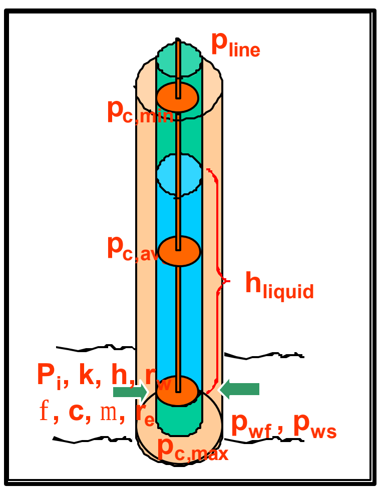

Fig. 1 – Schematic of a plunger at the bottom of the well with a liquid column above it.

An important parameter determining the efficiency of the production-lift performance is the duration of the production and shut-in periods. The methods used to determine the time periods, in general, are arbitrary and do not directly take into account the performance of the reservoir. One of the common procedures is to determine the time periods by trial and error and then put the plunger on a timer clock with predetermined production and shut-in periods. In the alternative, the flow rate is monitored and when the gas flow falls below a threshold rate, the well is shut in.

In this project, an optimization algorithm for the production and shut-in periods of plunger lift has been developed and implemented. This procedure is based on the reservoir performance and may accommodate the changes in the line pressure. The following activities have been undertaken and completed during the project:

Activity 1 - Development of a Production Optimization Algorithm: The development of the optimization algorithm was the main objective of the project. This activity included two specific tasks:

> ***Task 1.1 - Determination of Reservoir Properties:*** This task dealt with the necessity that the reservoir properties, such as permeability, porosity, skin, etc., must be known to condition the plunger lift operation to the reservoir performance. Normally, reservoir properties are determined by pressure-transient analysis but, because of cost considerations, stripper gas wells usually lack pressure transient data. A practical solution to this problem may be the use of production data. Therefore, investigating the potential of using production data to determine reservoir properties was one of the tasks of this project.

> ***Task 1.2 - Development of Production Optimization Algorithm:*** The main objective of this project was to optimize the plunger lift performance based on reservoir performance. This objective required simulating the reservoir performance to determine the optimum production and shut-in intervals so as to maximize the production from plunger lift. Particular emphasis has been given to the development of a robust algorithm that only required average reservoir properties and could be easily implemented on the existing well controls.

Activity 2 - Field-Testing and Validation of the Proposed Method: The algorithm and the method have been validated with the field data and implemented on a well. Three tasks have been involved in this activity:

> ***Task 2.1 – Building the Electronic Box:*** The implementation of the optimization method required manufacturing an electronic box, which included the production optimization algorithm and the switch controls.

> ***Task 2.2 – Field-Testing of the Method:*** The optimization algorithm and the electronic box have been tested by using the field data first and then by applying on a gas well produced by plunger lift.

> ***Task 2.3 – Final Report:*** Throughout the project, the results have been compiled to construct the final report to be presented to the Stripper Well Consortium.

The details of the above activities and the results obtained from the applications are reported in the following sections of this report.

EXPERIMENTAL

The proposed method of this research project was semi-analytical. No experimental task has been performed.

RESULTS AND DISCUSSION

The results of the project are documented and discussed below with respect to the specific activities and tasks proposed originally and documented in the Introduction. The details of the developments are provided in the Appendices.

Activity 1 - Development of a Production Optimization Algorithm:

Task 1.1 - Determination of Reservoir Properties:

The objective of this task was to investigate the possibility of using production data to obtain the reservoir properties required by the optimization algorithm. We have extensively investigated the methods proposed in the literature[1-3] to estimate the average reservoir properties by using the production history and proposed an extension of the existing methods. Below, we present a summary of our research on the determination of reservoir properties and original gas in place from production data. Additional details are given in Refs. 4 and 5 and Appendix A.

We first introduce the concept of dimensionless transient productivity index. We show that the dependence of the dimensionless transient productivity index on the bottomhole production conditions is a weak one and may be neglected for practical purposes of liquid production. This allows us to use the same set of type curves for constant and variable rate/pressure conditions at the bottomhole. As in the works of Palacio and Blasingame[1] and Agarwal et al.[2] We, then, extend these ideas to gas production conditions by using pseudopressure and pseudotime concepts discussed in the literature.[1,2]

Dimensionless Transient Productivity Index, J_D: Productivity index, J, is a conventional definition of a well's productivity under stabilized flow conditions and is defined by

$$J = \frac{q}{\overline{p} - p_{wf}}, \qquad (1)$$

where $\overline{p}$ represents the average reservoir pressure. For liquid wells and gas wells under Darcy flow conditions, the productivity index, J, is a constant and independent of the bottomhole flow conditions.[6]

In developing type-curves for the analysis of transient pressure responses, it is customary to define dimensionless variables as follows: The dimensionless bottomhole pressure based on the initial pressure, p_i, is defined by

$$p_{wD}(t_D) = \frac{kh}{141.2qBm}\left[p_i - p_{wf}(t)\right], \tag{2}$$

where q may be constant for constant-rate production or a function of time [$q = q(t)$] for variable-rate production.

It is possible to define a dimensionless bottomhole production rate by

$$q_D(t_D) = \frac{141.2q(t)Bm}{kh\left(p_i - p_{wf}\right)}, \tag{3}$$

where p_{wf} may be a fixed bottomhole pressure for production at a constant pressure or may change as a function of time [$p_{wf} = p_{wf}(t)$]. The dimensionless time is defined by

$$t_D = \frac{2.637 \times 10^{-4} kt}{fc_t m r_w^2}. \tag{4}$$

For our purposes, it is also possible to define a dimensionless bottomhole pressure based on average pressure, $\overline{p}$, as follows:

$$\tilde{p}_{wD}(t_D) = \frac{kh}{141.2qBm}\left[\overline{p} - p_{wf}(t)\right] = p_{wD} - \overline{p}_D, \tag{5}$$

where $\overline{p}_D$ is the dimensionless average pressure given by[6]

$$\overline{p}_D = \frac{kh}{141.2qBm}\left[p_i - \overline{p}(t)\right] = 2pt_{AD}, \tag{6}$$

and t_{AD} is a dimensionless time defined based on the drainage area, A , as follows

$$t_{AD} = \frac{2.637 \times 10^{-4} kt}{fc_t mA} = \frac{r_w^2}{A} t_D. \tag{7}$$

Similarly, we can define a dimensionless rate based on average pressure as follows:

$$\begin{aligned} \tilde{q}_D(t_{eD}) &= \frac{141.2q(t_e)Bm}{kh\left[\overline{p} - p_{wf}(t_e)\right]} = \frac{q_D(t_{eD})}{1 - \overline{p}_{Dcp}(t_{eD})} \\ &= \frac{1}{1/q_D(t_{eD}) - \overline{p}_D(t_{eAD})} \end{aligned}. \tag{8}$$

In Eq. 8, $\overline{p}_{Dcp}$ is the dimensionless average pressure for constant pressure production conditions given by[6]

$$\overline{p}_{Dcp} = \frac{p_i - \overline{p}(t_e)}{p_i - p_{wf}} = \frac{2pQ_D(t_{eD})}{A / r_w^2}, \tag{9}$$

where

$$\begin{aligned} Q_D(t_{eD}) &= \int_0^{t_{eD}} q_D(t)dt = \frac{3.723\times10^{-2} Q(t_e)B}{khfc_t r_w^2 (p_i - p_{wf})} \\ &= \frac{3.723\times10^{-2} B}{khfc_t r_w^2 (p_i - p_{wf})} \int_0^{t_e} q(t)dt \end{aligned}. \tag{10}$$

The last equality in Eq. 10 follows from the definition of average pressure $\overline{p}_D(t_{eAD})$ for general variable rate production conditions as follows:[6]

$$\overline{p}_D(t_{eAD}) = \frac{kh}{141.2q(t_e)Bm}[p_i - \overline{p}(t_e)] = 2pt_{eAD}, \tag{11}$$

where

$$t_e = \frac{1}{q(t)}\int_0^t q(t)dt = \frac{Q(t)}{q(t)}. \tag{12}$$

Note that t_e defined in Eq. 12 is the same as the material balance time used by Palacio and Blasingame.[1] Also note that for constant pressure production, $t_e = t$. Therefore, in the following discussions, we will use t_e for both constant rate and variable rate production conditions.

If we define a dimensionless transient productivity index, $J_D(t_D)$, as follows

$$J_D(t_{eD}) = \frac{141.2Bm}{kh} J(t_e), \tag{13}$$

where

$$J(t_e) = \frac{q(t_e)}{\overline{p} - p_{wf}(t_e)}, \tag{14}$$

then, Eqs. 5, 6, 13, and 14 may be combined to yield

$$J_D(t_{eD}) = \frac{1}{\tilde{p}_{wD}(t_{eD})} \qquad \text{for constant rate production,} \qquad (15)$$

and

$$J_D(t_{eD}) = \tilde{q}_D(t_{eD}) \qquad \text{for variable rate production.} \qquad (16)$$

We may now note the following features of the dimensionless transient productivity index: During transient flow periods, because $\overline{p} \approx p_i$, we have

$$J_D(t_{eD}) = \frac{1}{p_{wD}(t_{eD})} \qquad (17)$$

or

$$J_D(t_{eD}) = q_D(t_{eD}), \qquad (18)$$

(depending on the bottomhole flow conditions) where $p_{wD}(t_D)$ and $q_D(t_D)$ represent the conventional dimensionless pressure and rate defined by Eqs. 2 and 3, respectively. This implies that the transient flow portions of the theoretical dimensionless transient productivity-index curves may be constructed by using the conventional type curves used for well test analysis.

At late times, when the boundary effects dominate the well response, $J(t_e)$ term defined in Eq. 14 becomes a constant (assuming Darcy flow conditions) equal to J defined in Eq. 1. Therefore, the boundary dominated flow portion of the dimensionless transient productivity index curve is a constant that is proportional to the inflow performance relationship for the given well/reservoir system. Figure 2 shows a production decline type curve for a vertical well in a closed circular reservoir. Each curve on the type curve corresponds to a specific value of dimensionless drainage radius, $r_{eD} = r_e/r_w$, noted on the figure. The curves shown on Fig. 2 have been generated by numerically inverting the known analytical solutions in the Laplace domain (see Appendix A).

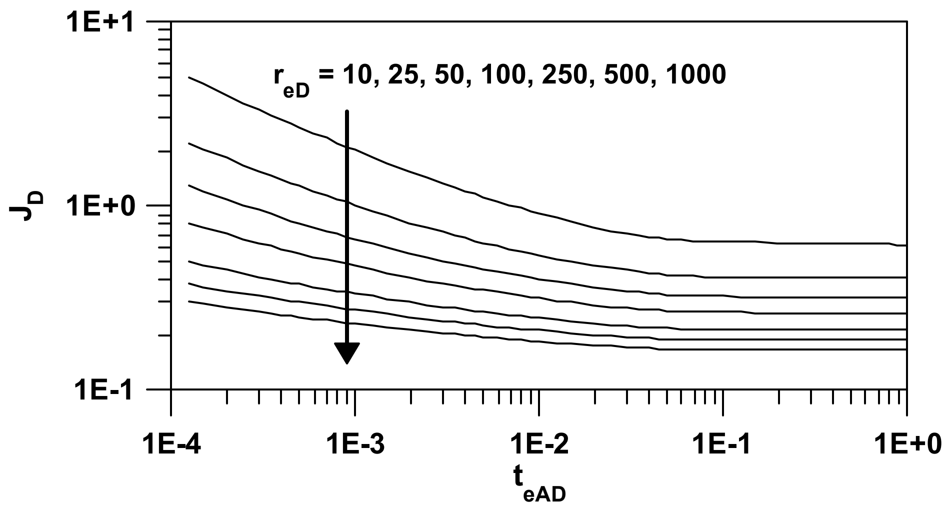

Fig. 2 – Production decline type curve in terms of dimensionless productivity index for a vertical well in a closed circular reservoir.

Effect of Mode of Production on J_D: As discussed by Palacio and Blasingame[1] and Agarwal et al.,[2] $q_D(t_{eD})$ vs. t_{eD} for constant bottomhole production (BHP) should follow the constant rate production (CRP) responses plotted in terms of $1/p_{wD}(t_{eD})$ versus t_{eD}. Here, we apply these ideas to dimensionless productivity index and investigate the equivalence of the transient productivity indices for constant rate and constant pressure production conditions; that is, we investigate the possibility that $\tilde{q}_D(t_{eD})$ versus t_{eD} curves follow $1/\tilde{p}_{wD}(t_{eD})$ versus t_{eD}, where $\tilde{q}_D$ and $\tilde{p}_{wD}$ are defined by Eqs. 5 and 8, respectively.

For a vertical well in a bounded reservoir, it is a well-known result that $q_D(t_D) \approx 1/p_{wD}(t_D)$ during transient flow period. Because during transient flow, $q_D(t_D) \approx \tilde{q}(t_D)$ and $p_{wD}(t_D) \approx \tilde{p}_{wD}(t_D)$, we can expect to have $\tilde{q}_D(t_{eD})$ versus t_{eD} curves for constant pressure production to follow $1/\tilde{p}_{wD}(t_{eD})$ versus t_{eD} curves for constant rate production. Therefore, the dimensionless productivity index, J_D, should be approximately independent of wellbore production conditions during transient flow period. Also, at late times (boundary dominated flow), $J = q/(\bar{p} - p_{wf})$ is approximately independent from the production conditions,[6] which by Eqs. 15 and 16 implies that the dimensionless productivity index, J_D, should also be independent of the production conditions at late times. Then, we may expect to have $J_D(t_{eD})$ to be approximately independent of the production conditions for all times.

Figure 3 compares the dimensionless productivity indices of a vertical well in a closed cylindrical reservoir of dimensionless radius, $r_{eD} = r_e/r_w = 20$ under constant-rate production (the unbroken line in Fig. 3) and constant-pressure production (the circular data points) conditions.[4,5] These results were generated by numerically inverting the analytical solutions in the Laplace domain (see Appendix A). The agreement of the results during the late times (when the dimensionless productivity index becomes a constant) is satisfactory. During the transient flow period, the results for the constant-pressure production case are slightly below the results for the constant-rate production case, but the agreement is acceptable for practical purposes. Also for comparison, Fig. 3 shows $1/p_{wD}$ and q_D vs. t_{eD} (the dashed line and the square data points, respectively) as suggested by Refs. 1 and 2. The agreement between the constant pressure and constant rate production results is similar to that observed for the transient productivity index results.

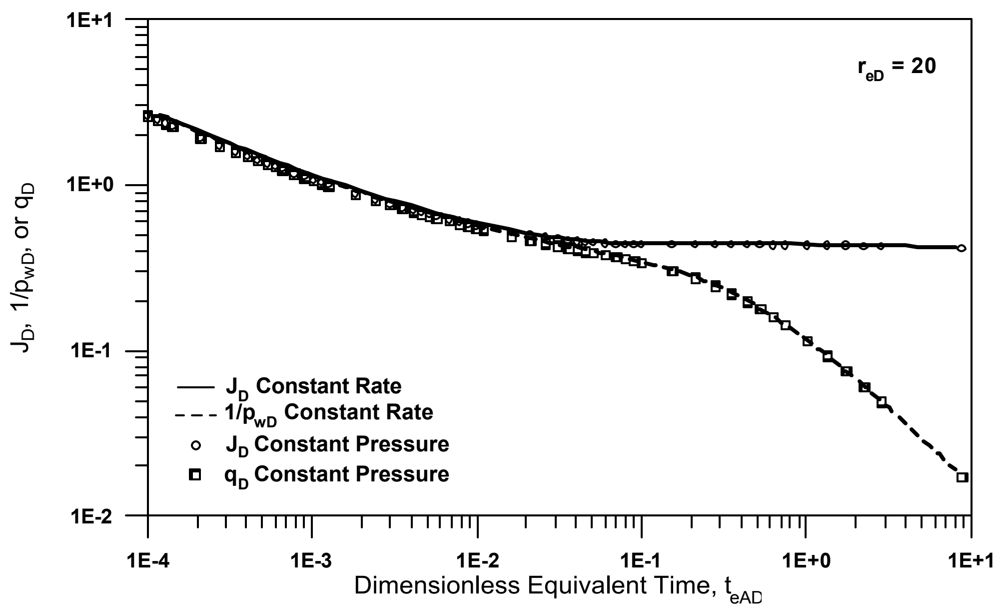

Fig. 3 – Comparison of production decline type curves for constant rate and constant pressure production conditions.[4,5]

Extension to Gas Reservoirs: The ideas developed above may be extended to gas reservoirs by using the pseudopressure and pseudoequivalent time[1,2] defined, respectively, by

$$m(p) = 2\int_{p_0}^{p} \frac{p'}{m\,Z}\,dp' , \tag{19}$$

where p_0 is an arbitrary datum pressure, and

$$
\begin{aligned}
t_a &= \frac{\mu_i c_{ti}}{q(t)} \int_0^t \frac{q}{\mu(\overline{p}) c_t(\overline{p})} dt \\
&= \frac{\mu_i c_{ti}}{q(t)} \frac{Z_i G}{2 p_i} \left[m(\overline{p}) - m(p_{wf}) \right]
\end{aligned}
\tag{20}
$$

where G is the gas in place and the subscript i indicates the initial conditions. Note that the computation of the pseudoequivalent time given in Eq. 20 requires estimates of fluid properties as a function of the average reservoir pressure. The average reservoir pressure profile may be estimated from an estimate of gas in place, G, by using the gas material balance equation given by

$$
\frac{1}{G} = \frac{1}{G_p} \left[1 - \frac{\overline{p}}{\overline{Z}} \frac{Z_i}{p_i} \right]. \tag{21}
$$

If the gas in place is not known, the iterative procedure discussed below in the Analysis Technique section may be used to obtain an estimate of G.

The dimensionless versions of the pseudopressure based on the initial and average pressures are given, respectively, by

$$
m_{wD}(t_{aD}) = \frac{kh}{1422Tq} \left[m(p_i) - m(p_{wf}) \right], \tag{22}
$$

and

$$
\tilde{m}_{wD}(t_{aD}) = \frac{kh}{1422Tq} \left[m(\overline{p}) - m(p_{wf}) \right]. \tag{23}
$$

The dimensionless pseudoequivalent times based on the wellbore radius, r_w, and drainage area, A, are defined, respectively, by

$$
t_{aD} = \frac{2.637 \times 10^{-4} k t_a}{\phi (\mu c_t)_i r_w^2}, \tag{24}
$$

and

$$
t_{aAD} = \frac{2.637 \times 10^{-4} k t_a}{\phi (\mu c_t)_i A}. \tag{25}
$$

We also define the dimensionless production rate based on initial and average pressure as shown, respectively, below.

$$q_D(t_{aD}) = \frac{1422Tq(t_a)}{kh\left[m(p_i) - m(p_{wf})\right]}, \tag{26}$$

and

$$\widetilde{q}_D(t_{aD}) = \frac{1422Tq(t_a)}{kh\left[m(\overline{p}) - m(p_{wf})\right]}. \tag{27}$$

We also use the definition of dimensionless cumulative production given below.

$$\begin{aligned} Q_{aD}(t_{aD}) &= q_D t_{aD} \\ &= \frac{9.0T}{fh\left[m(p_i) - m(p_{wf})\right]r_w^2} \int_0^t \frac{q(t)}{m(\overline{p})c_g(\overline{p})} dt\ . \\ &= \frac{4.5TZ_iG}{fhr_w^2 p_i}\left[\frac{m(p_i) - m(\overline{p})}{m(p_i) - m(p_{wf})}\right] \end{aligned} \tag{28}$$

We can, now, note the following relations:

$$\widetilde{m}_{wD}(t_{aD}) = m_{wD}(t_{aD}) - m_D(\overline{p}), \tag{29}$$

where

$$m_D(\overline{p}) = 2pt_{aAD}, \tag{30}$$

and

$$\widetilde{q}_D(t_{aD}) = \frac{q_D(t_{aD})}{1 - m_{Dcp}(\overline{p})} = \frac{1}{1/q_D(t_{aD}) - m_D(\overline{p}_D)}, \tag{31}$$

where

$$m_{Dcp}(\overline{p}) = \frac{p_i - \overline{p}(t_a)}{p_i - p_{wf}} = \frac{2pQ_{aD}(t_{aD})}{A/r_w^2}, \tag{32}$$

and

$$m_D(\overline{p}_D) = 2pt_{aAD}. \tag{33}$$

Using the above relations, we may define the dimensionless productivity index for gas wells as follows:

$$J_D(t_{aD}) = \frac{kh}{1422T} J(t_a), \tag{34}$$

where

$$J(t_a) = \frac{q(t_a)}{m(\bar{p}) - m(p_{wf})}. \tag{35}$$

Because the gas well responses in terms of pseudopressure should follow the liquid well responses in terms of pressure, and the definition of the pseudoequivalent time should remove the dependency of the transient productivity index on the mode of production, we can expect to have the dimensionless transient productivity index for gas wells to follow that for liquid wells. Numerical proof of these ideas has been presented in Ref. 4.

Analysis Technique: The objective of the decline-type-curve analysis is to determine the reserves and reservoir properties. The analysis technique is similar to that proposed by Agarwal *et* al.[2] and uses the ideas presented by Palacio and Blasingame.[1]

First, an estimate of the original gas in place, *G*, should be obtained. As suggested by Agarwal *et* al.[2] a trial and error procedure may be used to estimate *G*. An initial guess may be chosen between the cumulative gas production (lower limit) and the volumetric estimate from petrophysical data (upper limit) to start iterations. It is shown in Fig. 4 that an underestimation of the *G* will cause an upward bend (increase) of the productivity index during boundary dominated flow, whereas an overestimation will cause a downward bend (decrease). The convergence to a correct estimate will be verified by a constant productivity index during the boundary dominated flow period. In this iteration process, convergence is usually obtained rapidly.

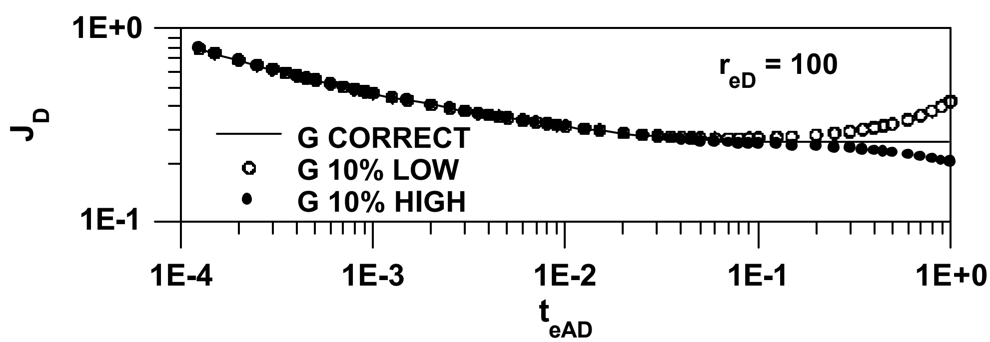

Fig. 4 – Iterative estimation of the gas in place, *G*.

After an accurate estimate of *G* is obtained, the analysis continues with type curve matching to estimate the permeability. The productivity index curve computed from the field data is matched with one of the type curves, for example, on Fig. 2. Once a reasonably good match is obtained, a match point (M.P.) is chosen and the corresponding values of the dimensionless (type curve) and field (data) productivity indices and the dimensionless (type-curve) and dimensional (data) times are noted. The match point values are then used in the following equation to estimate the permeability:

$$k = \frac{1422T}{h} \frac{\left\{ \frac{q}{\left[m(\bar{p}) - m(p_{wf}) \right]} \right\}_{M.P.}}{\left[J_D \right]_{M.P.}} . \tag{36}$$

After estimating the permeability, k, an estimation of G may be obtained from the following equation:

$$G = \frac{6.3288 \cdot 10^{-3} kh}{5.615 m_i c_{ti} B_{gi}} \frac{[t]_{M.P.}}{[t_{AD}]_{M.P.}} . \tag{37}$$

The theoretical development presented above is independent of the type of well used in the production. The only minor modification required is the replacement of the wellbore radius, r_w, used in the dimensionless definitions by the half-length of the fracture and well for fractured and horizontal wells, respectively. References 4 and 5 present the application of these ideas to horizontal wells.

Application Example: Here, we consider the example application discussed in Refs. 4 and 5 for a horizontal gas well produced at a constant rate, $q = 8000$ MSCF/d. The properties of the horizontal well and reservoir are presented in Table 1 and the measured bottomhole pressure, p_{wf}, and the corresponding pseudopressures, $m(p)$, are shown in Fig. 5 as a function of time.

Table 1 – Reservoir and fluid data for the example application.[4]

A, area, Acres	574
B_{gi}, formation volume factor, RB/MSCF	0.6822
c_{ti}, total compressibility, psi^{-1}	0.0001516
h, formation thickness, ft	36
L, horizontal well length, ft	1500
p_i, initial pressure, psi	4,700
k, permeability, md	8
f, porosity, fraction	0.09
r_w, wellbore radius, ft	0.3
S_g, gas saturation, fraction	0.5538
T, reservoir temperature, °R	640
m, viscosity, cp	0.022391
z_i, initial gas compressibility factor	0.99307

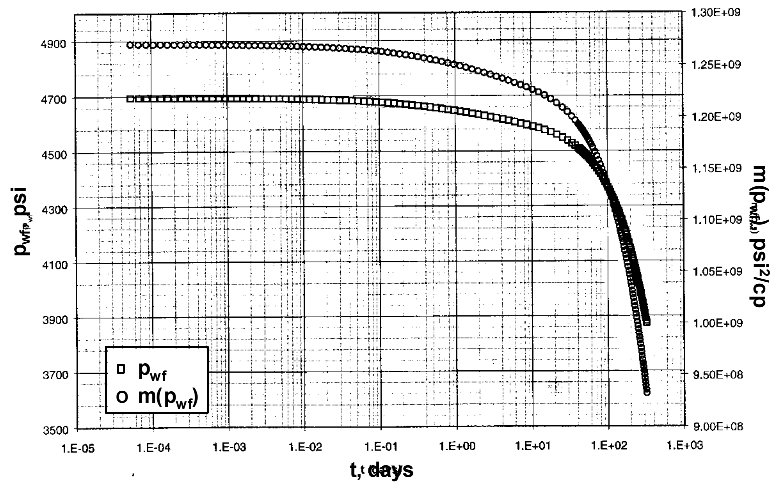

Fig. 5 – Pressure and pseudopressures vs. time for the example application of decline type-curve analysis.[4]

To start the analysis, original gas in place, *G*, should be estimated first. The estimation of *G* requires an iterative procedure as discussed above. For this example, an initial guess may be considered between the lower and upper bounds for *G* estimated as 19.03×10^6 and 23.25×10^6 MSCF, respectively. Using the initial guess for *G* and the material balance equation given by Eq. 20, the average pressures and, then, the productivity index, $q/\left[m(\bar{p}) - m(p_{wf})\right]$, may be computed as a function of pseudoequivalent time, t_a. This procedure is repeated until a reasonably constant productivity index is obtained during the boundary-dominated flow. Figure 6 shows the iteration process and indicates that $G = 21.14 \times 10^6$ MSCF is a good estimate for the GIP.

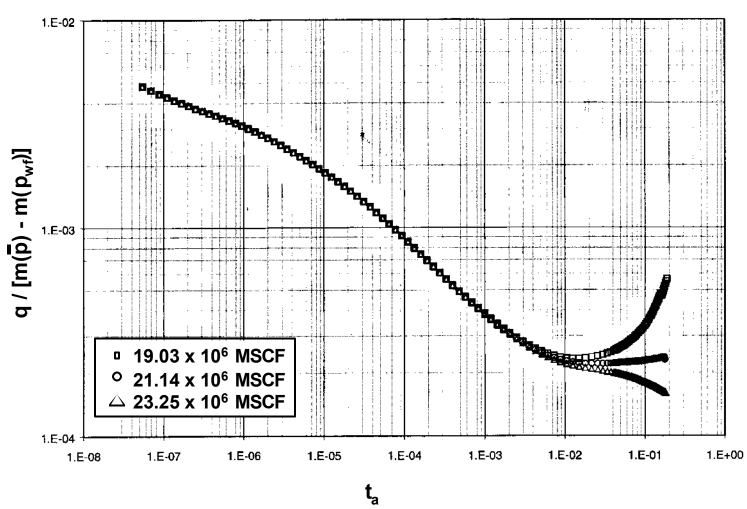

Fig. 6 – Iterative estimation of the original gas in place for the example application.[4]

Once a good estimate of G is obtained, then the corresponding productivity index may be analyzed by type-curve matching. Figure 7 shows the match of the productivity index data with the appropriate horizontal well type-curve.[4,5] The following match points may be chosen for the example analysis:

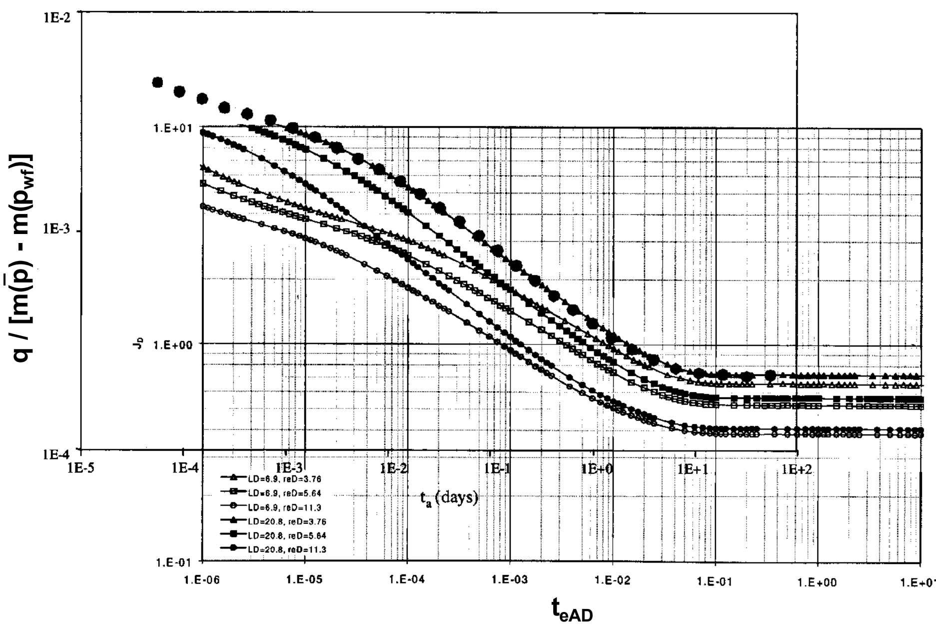

Fig. 7 – Decline type-curve analysis for the example application.[4]

$$[t]_{M.P.} = 1.5,$$

$$[t_{eAD}]_{M.P.} = 1\times 10^{-2},$$

$$\left\{\frac{q_g}{\left[m(\overline{p}) - m\left(p_{wf}\right)\right]}\right\}_{M.P.} = 3\times 10^{-4},$$

and

$$[J_D]_{M.P.} = 0.98.$$

By using Eqs. 36 and 37, we estimate the following values of k and G, respectively:

$$k = 7.74\ mD,$$

and

$$G = 20.34 \times 10^{6}\ MSCF\ .$$

It can be seen that the estimates of G from the iteration process and type-curve matching are in good agreement.

Although the theory developed above and the application example indicate that production data may be used to estimate the properties of reservoirs similar to pressure transient analysis, we have found that the application would normally suffer from the quality of the production data especially during transient flow periods.[3-5] As in most stripper gas wells, if the production data is based on daily gas measurements at the collector or separator, the quality of the data does not meed the requiremets of decline-type-curve analysis. Specifically for this project, we tested the production data provided by Marjo Operating Company and concluded that the quality of the data was insufficient for the application of decline-type-curve analysis. Therefore, for the stripper gas wells, the estimation of the reservoir properties need to be by conventional techniques (cores, logs, and pressure-transient tests) unless measures are taken to estimate gas production with accuracy close to that for pressure-transient measurements.

Task 1.2 – Development of Production Optimization Algorithm:

The main task of this project was to develop an optimization method for plunger lift operation based on reservoir performance. The idea behind this optimization method is to find the longest production period for which the liquid accumulated in the wellbore can be lifted by the pressure that builds up during the following shut-in period. To explain the production optimization algorithm, the following analysis of the plunger-lift operation may be helpful:

1. During shut-in, the plunger sits at the bottom of the wellbore with a liquid column from the previous production period above it (see Fig. 1). When the well is open to production, because of the pressure differential between the casing (which is equal to the sandface pressure of the reservoir) and the tubing-head pressure (which is mainly controlled by the line pressure), the plunger starts moving up and the liquid above the plunger is produced with the gas at the surface. If the pressure differential is sufficient to overcome the forces acting upon the fluids in the tubing, then the plunger may reach the surface, and all the liquid from the previous production period may be removed from the wellbore. Production of gas may continue after the plunger reaches the surface.

2. During the production period, while the liquid from the previous production period is removed by the lift of the plunger, new liquid in the produced gas starts accumulating in the tubing below the plunger. The height of the liquid column depends on the liquid content of the gas and the duration of the production period. During production, the sandface pressure (casing pressure)

drops because of the withdrawal of fluids from the reservoir and the tubing pressure increases because of the accumulation of the liquid.

3. Production stops either because the differential pressure between the sandface and the tubing becomes zero or the well is shut in (for successful plunger lift design, the pressure differential should not drop to zero before the plunger reaches the surface). At this time, the plunger starts descending in the tubing (the one-way valve on the plunger allows the liquid to rise above the plunger) until it rests at the bottom with the liquid column above it.

4. During the shut-in period, reservoir flow builds up the pressure at the sandface (casing) to a level sufficient to push the plunger and the liquid column above it to the surface.

The objective of the optimization is to determine the optimum production and buildup times to maximize the cumulative production. To maximize production, it is desirable to make the production periods longer and buildup periods shorter. Longer production periods, however, require longer shut-in times to build the pressure up to the level required to lift the fluids to the surface. Therefore, an optimum needs to be found for the production and shut-in times so that the cumulative production for a given sequence of production and shut-in periods is maximized. Because the optimization of the production time requires the knowledge on the buildup performance, which is chronologically later in the plunger-lift sequence, real-time measurements of tubing and casing pressures cannot be used in this optimization problem. We used analytical models of the wellbore and reservoir to simulate the production and buildup performances and developed an iterative algorithm to determine the optimum production and buildup times.

Below, we summarize the models used to simulate the wellbore hydraulics during plunger lift and reservoir performance during the production and shut-in periods. Next, we discuss the iterative algorithm to couple the wellbore hydraulics and reservoir performance to determine the optimum production and shut-in periods.

Wellbore Hydraulics for Plunger Lift: For the purposes of this project, we needed to know the change in the bottomhole pressure during production as a function of time. Specifically, we needed a model to simulate the effect of wellbore hydraulics on the bottomhole pressure during production. The results presented in Refs. 7 – 9 were helpful to simulate the wellbore hydraulics during plunger lift.

Foss and Gaul[7] presented the following pressure-balance equation when the plunger is rising in the tubing with its liquid load:

$$
\begin{aligned}
&Casing\ pressure + pressure\ due\ to\ the\ weight\ of\ gas\ column \\
&- gas\ frictional\ pressure\ drop\ in\ the\ annulus = \\
&\ \ gas\ frictional\ pressure\ drop\ in\ the\ tubing\ under\ the\ plunger \\
&+ pressure\ due\ to\ the\ weight\ of\ the\ gas\ column\ under\ the\ plunger \\
&+ plunger\ frictional\ pressure\ drop \\
&+ pressure\ required\ to\ lift\ the\ plunger\ weight \\
&+ pressure\ required\ to\ lift\ the\ liquid\ weight \\
&+ liquid\ frictional\ pressure\ drop \\
&+ gas\ frictional\ pressure\ drop\ above\ the\ plunger \\
&+ pressure\ due\ to\ the\ weight\ of\ the\ gas\ column\ above\ the\ plunger \\
&+ surface\ tubing\ back\ pressure \\
&+ pressure\ of\ the\ produced\ liquid\ under\ the\ plunger
\end{aligned}
\qquad (38)
$$

Although Eq. 38 indicates that the casing pressure changes from a maximum when the plunger starts rising from the bottom of the tubing to a minimum when the liquid slug and the plunger reaches the surface,[7-9] in our model we assume that the production period is characterized by a constant bottomhole pressure. From Eq. 38, it can be shown that the average casing pressure, $p_{c,avg}$, during production is given by[7]

$$p_{c,avg} = \left(1 + \frac{A_t}{2A_a}\right)\left(1 + \frac{D}{K}\right) p_L \qquad (39)$$

where

A_t : tubing cross-sectional area, ft^2,

A_a : annulus cross-sectional area, ft^2,

D : tubing depth, ft,

K : gas friction term, ft,

$$p_L = p_p + p_t + \left(p_{1h} + p_{1f}\right) V_l + 14.7 \text{, psi,} \qquad (40)$$

p_p : pressure to lift the plunger weight, psi,

p_t : flowline pressure, psi,

p_{1h} : pressure to lift 1 bbl of fluid in the tubing, psi,

p_{1f} : frictional pressure loss per barrel of liquid, psi, and

V_l : liquid volume above the plunger, bbl.

In Eq. 40, p_{1h} and p_{1f} may be computed from the following equations, respectively:[7,9]

$$p_{1h} = 0.433 g_l \left(\frac{5.615}{A_t} \right), \tag{41}$$

and

$$p_{1f} = \frac{0.433 g_l f_l v_p^2}{2\left(d_t/12\right)(32.2)(144)} \left(\frac{5.615}{A_t} \right), \tag{42}$$

where

g_l : specific gravity of the liquid

f_l : liquid friction factor in the tubing

v_p : average plunger velocity during production, ft/s,

and

d_t : tubing diameter, in.

The gas friction term, K, in Eq. 39 may be computed from the following equation[8,9]

$$\frac{1}{K} = \frac{f_g v_p^2 g_g}{2\left(d_t/12\right)(32.2)(T+460)(10.732)(144)Z}, \tag{43}$$

where

f_g : gas friction factor in the tubing,

g_g : specific gravity of gas,

T : average temperature in the tubing, °F,

and

Z : gas compressibility factor.

In this project, to compute the friction factor, f, for turbulent flow ($N_{Re} > 2300$), we used the Colebrook[10] correlation given by

$$\frac{1}{\sqrt{f}} = 1.74 - 2\,log\left(\frac{2e}{d_t} + \frac{18.7}{N_{Re}\sqrt{f}}\right), \tag{44}$$

where e is the surface roughness of the tubing and N_{Re} is the Reynolds number given by

$$N_{Re} = 4.71 \times 10^{-3} \frac{g\, v_p\, d_t}{(10.732)m\,(T + 460)Z}. \tag{45}$$

For laminar flow ($N_{Re} \leq 2300$), the friction factor was calculated from the following relation:

$$f = \frac{64}{N_{Re}}. \tag{46}$$

Another critical piece of information for plunger-lift optimization is the pressure when the plunger starts ascending from the bottom of the tubing (that is, the pressure at the beginning of the production period). This pressure should be sufficient to lift the plunger and its liquid load to the surface and is determined by the potential of the reservoir and the length of the pressure buildup period. If the liquid load from the previous production period is known, then the plunger-lift pressure model (Eq. 38) can provide the minimum pressure necessary to lift the plunger to the surface. Because this pressure is to be reached during the buildup period, a reservoir model can be used to determine the duration of the buildup period.

According to the Foss and Gaul[7] theory, when the plunger starts ascending in the tubing, the casing pressure is maximum and is given by[7,8]

$$p_{c,max} = 2p_{c,avg}\left(\frac{A_a + A_t}{2A_a + A_t}\right). \tag{47}$$

The casing pressure decreases as the plunger rises in the tubing and becomes a minimum when the plunger reaches the top of the tubing. The minimum casing pressure during plunger lift is given by[7,8]

$$p_{c,min} = 2p_{c,avg}\left(\frac{A_a}{2A_a + A_t}\right). \tag{48}$$

To determine the average and maximum casing pressures by using Eqs. 39 and 47, respectively, the liquid column height (and hence the production) must be known. Therefore, the plunger-lift optimization algorithm should relate Eqs. 39 and 47 to a reservoir performance model. Below, we discuss the reservoir model used in the optimization algorithm.

Reservoir Performance Model for Plunger Lift: As noted above, to predict the reservoir performance during production, we assumed a constant flowing bottomhole pressure, $p_{wf,cp}$, equal to the average casing pressure, $p_{c,avg}$, in this project. This is for convenience for the optimization algorithm and may be justified based on the claim that the production does not change significantly during plunger lift production from tight gas wells even if the bottomhole pressure is changed.[9] Because our main interest is to determine the height of the liquid column, a reasonably good estimate of the cumulative production at the end of the production period must be sufficient for our purposes. (It should be noted that the same cumulative production would require different production times under constant rate and constant pressure production conditions. Our numerical experiments, however, indicated that the constant pressure production assumption would yield conservative estimates of the production times.)

Because the production (drawdown) period is followed by a shut-in (buildup) period in plunger lift operation, we first attempted to model a sequence of constant-pressure production followed by shut in. Although we were able to derive several approximate solutions, as discussed in our Third-Quarter Report,[11] the numerical evaluation of the solutions posed problems because of the discontinuity involved at the instant of shut-in. Similar problems, have also been reported in the literature.[12-15] In general, the solutions provided reasonably accurate buildup pressures for shut-in times much smaller than the producing time. In realistic plunger-lift operation conditions, however, producing times are much shorter than the buildup times. Therefore, we could not use the approximate analytical solutions for buildup pressures following production at a constant pressure. The alternative to a combined solution for the production and shut-in periods is to model each flow period separately.

Below, the production and buildup models used for reservoir pressure calculations are discussed. Following the standard procedures, gas-flow solutions in porous medium are presented in terms of pseudopressure, $m(p)$, defined by Eq. 19. Because the measurements in the field and the wellbore hydraulics model discussed above are in terms of pressure, the coupling of the wellbore and reservoir solutions is carried out in terms of pressure. This requires generating a table of pseudopressure versus pressure for the range of interest of the pressures. This table is then used to convert pressure to pseudopressure and vice versa by a table-look-up procedure with interpolation.

a) Production period:

Using Duhamel's equation,[6] the following relation between the pseudo pressure drop due to constant pressure production, $Dm_{wf,cp}$, and constant unit-rate production, $Dm_{wf,ur}$, may be written as follows:

$$Dm_{wf,cp}(t) = \int_0^t q(t)Dm'_{wf,ur}(t-t)dt \;, \tag{49}$$

where $q(t)$ is the gas production rate in MSCFD at the constant pressure $Dm_{wf,cp}$,

$$Dm'_{wf,ur}(t) = \frac{\partial Dm'_{wf,ur}}{\partial t}(t), \tag{50}$$

and

$$Dm_{wf} = m(p_i) - m(p_{wf}). \tag{51}$$

As discussed above, we assume that the constant flowing bottomhole pseudopressure, $Dm_{wf,cp}$, may be approximated by the pseudopressure corresponding to the average casing pressure, $p_{c,avg}$, given by Eq. 39 during production.

Evaluating the Laplace transform of Eq. 49, the following equations to calculate the gas production rate, $\overline{q}(s)$, and cumulative gas production, $\overline{Q}(s)$, in Laplace domain are obtained:

$$\overline{q}(s) = \frac{Dm_{wf,cp}}{s^2 D\overline{m}_{wf,ur}} \;, \tag{52}$$

and

$$\overline{Q}(s) = \frac{\overline{q}(s)}{s}. \tag{53}$$

where s is the Laplace transform parameter.

In Eq. 52, $D\overline{m}_{wf,ur}$ (the Laplace transform of the pseudopressure drop due to production at a constant unit rate) is given by[16]

$$D\overline{m}_{wf,ur} = \frac{1422T}{khs}\left\{\frac{I_0\left(\sqrt{s/h}\,r_w\right)K_1\left(\sqrt{s/h}\,r_e\right) + I_1\left(\sqrt{s/h}\,r_e\right)K_0\left(\sqrt{s/h}\,r_w\right)}{\sqrt{s/h}\,r_w\left[I_1\left(\sqrt{s/h}\,r_e\right)K_1\left(\sqrt{s/h}\,r_w\right) - I_1\left(\sqrt{s/h}\,r_w\right)K_1\left(\sqrt{s/h}\,r_e\right)\right]} + S\right\} \tag{54}$$

where I_0, K_0, I_1, and K_1 are the modified Bessel functions, r_w and r_e are the wellbore and reservoir radii (in ft), respectively, S is the skin factor, T is the average reservoir temperature in (°R), k is the permeability (in md), h is the formation thickness in (ft) and

$$h = \frac{2.637 \times 10^{-4} k}{f \, \overline{cm}}. \tag{55}$$

In Eq. 55, $\overline{cm}$ is the average compressibility viscosity product given by[6]

$$\overline{cm} = \frac{1}{t} \int_0^t c(\overline{p}) m(\overline{p}) dt \ , \tag{56}$$

where $\overline{p}$ is the average reservoir pressure. For our purposes, because producing times are usually short, we evaluated cm product at the initial pressure so that

$$\overline{cm} = c(p_i) m(p_i). \tag{57}$$

When the reservoir boundaries do not influence the well response: that is, when

$$t < 0.1 \frac{p r_e^2}{h}, \tag{58}$$

the solution for $D\overline{m}_{wf,ur}$ given in Eq. 54 may be replaced by

$$D\overline{m}_{wf,ur} = \frac{1422T}{khs} \left[\frac{K_0\left(\sqrt{s/h}\, r_w\right)}{\sqrt{s/h}\, r_w K_1\left(\sqrt{s/h}\, r_w\right)} + S \right]. \tag{59}$$

For most practical cases we tested during this project, the production period satisfied the time condition given by Eq. 58 and we could use Eq. 59 instead of Eq. 54.

The solutions given in Eqs. 52, 53, 54, and 59 are in the Laplace transform domain and need to be numerically inverted into the real-time domain. We used the Stehfest's algorithm[17] discussed in Appendix A for numerical inversion. The solutions discussed above also assume that the pressure is uniform in the reservoir and equal to p_i at the beginning of the production period. In our application, each production period follows a period of shut-in, which may not be long enough to reach a stabilized pressure. We tested two approximations for this problem. The first approximation was to use the last shut-in pressure as the initial pressure (as in the modified isochronal testing of gas wells) and the second approach was to calculate an average pressure at the end of each production period, t_p, and use this average pressure as the initial pressure for the next production period. The average reservoir pressure was calculated from the following material balance equation:

$$m(\overline{p}) = m(p_i) - \frac{1422ThQ(t_p)}{24khr_e^2}, \tag{60}$$

where p_i corresponded to the initial pressure for the first flow period and to the average pressure at the end of the previous flow period for the consecutive flow periods. The latter of the two approaches provided better results because it approximately satisfied the material balance while the first approach was completely arbitrary (although it is used in modified isochronal testing of gas wells.)

One final remark on the solution given in Eq. 54 is about the shape of the reservoir. In this project, we assumed that a cylinder could approximate the reservoir shape because for the practical cases we used to test the algorithm, the production periods were not long enough to feel the effect of the reservoir boundaries. This approximation, however, is not a limitation for the general application because analytical solutions for many different reservoir geometries are available in the literature and may be easily used instead of Eq. 54.

b) Buildup period

Although the analytical solution for pressure buildup following constant rate production is well known, changing flow rate complicates the solutions. The problem of varying flow rate prior to shut-in has been addressed in the pressure-transient analysis literature[6,18-21] and several practical approaches have been proposed. In this project, we followed the suggestion of Horner[18] and used the analytical solution for pressure buildup following a production period, t_p, at a constant rate equal to the last rate prior to shut-in, $q(t_p)$. In this approach, a modified producing time, $\tilde{t}_p$, calculated by

$$\tilde{t}_p = \frac{Q(t_p)}{q(t_p)}, \tag{61}$$

replaced the actual producing time, t_p. In Eq. 61, $Q(t_p)$ denotes the cumulative production during the flow period. We chose this approach because it is relatively simple and it satisfies the material balance. (It should, however, be noted that the justification for the use of this and the other approaches presented in the pressure-transient analysis literature is based on the existence of a longer straight-line on a Horner plot; not on the accuracy of the estimated pressures. In addition, producing times much longer than the buildup time are required.[6,18-21] Because our interest in this project is in the magnitude of the pressures, we used the above approach with reservations.)

With the above modification of the producing time, in this project we used the solution for pressure buildup following constant-rate production in Laplace domain presented by Correa and Ramey:[22].

$$D\overline{m}_{ws} = \frac{D\overline{m}_{wf,ur}}{s\left(1+24Cs^2 D\overline{m}_{wf,ur}\right)}\left(1-e^{-s\tilde{t}_p}\right), \tag{62}$$

where C is the wellbore storage coefficient defined by Eq. B-10 in Appendix B.

Because the solution given in Eq. 62 is in the Laplace transform domain, the results are numerically inverted into the real-time domain by using the Stehfest's algorithm[17] (Appendix A). However, because of the discontinuity involved at time $t = \tilde{t}_p$, the numerical inversion of the solution given by Eq. 62 poses problems. We used the approached suggested by Chen and Raghavan[23] to calculate the pressure buildup responses. A summary of the calculation procedure is presented in Appendix C.

Optimization Algorithm: The following ideas are used in the construction of the optimization algorithm: During production, the bottomhole flowing pressure, p_{wf}, is between the minimum and maximum casing pressures; that is,

$$p_{c,min} \leq p_{wf} \leq p_{c,max}. \tag{63}$$

We assume that p_{wf} may be represented by the average casing pressure, $p_{c,avg}$, given by Eq. 39:

$$p_{wf} \approx p_{c,avg}. \tag{64}$$

Similarly, at the end of the buildup period, we require that the buildup pressure, p_{ws}, at the sandface must be equal to or larger than the maximum casing pressure, $p_{c,max}$, given by Eq. 47; that is,

$$p_{ws} \geq p_{c,max}. \tag{65}$$

We note, however, that both $p_{c,avg}$ and $p_{c,max}$ are functions of the liquid volume accumulated in the tubing during the production period. The liquid accumulation, on the other hand, is a function of the Gas Liquid Ratio (*GLR*) and cumulative production, which, itself, is a function of the production period, t_p, and constant production pressure, $p_{wf} \approx p_{c,avg}$. Therefore, the calculations of $p_{c,avg}$ and $p_{c,max}$ require the knowledge of $p_{c,avg}$. This imposes the use of an iterative solution procedure.

There are several iterative loops in the calculations. We first consider the calculation of the cumulative production, $Q(t_p)$ for a given value of t_p (we will have to iterate on t_p later). To begin the calculations, we make an initial guess for $p_{c,avg}$ and use $p_{wf} \approx p_{c,avg}$ in Eqs. 52 and 53 to calculate $q(t_p)$ and $Q(t_p)$. Using the calculated cumulative production, $Q(t_p)$, and the known *GLR*, we calculate the liquid volume accumulated in the tubing by the following expression:

$$V_l = \frac{1000 \times Q}{5.615 \times GLR}(bbl). \tag{66}$$

Knowing the liquid volume in the tubing, V_l, we calculate $p_{c,avg}$ from Eq. 39 and compare with the assumed value in the beginning of the calculations. If the calculated and assumed pressures are within 1%, we accept the calculated $p_{c,avg}$ as the correct pressure and the corresponding $q(t_p)$ and $Q(t_p)$ values as the correct rate and cumulative production, respectively. If the difference between the calculated and assumed pressures is higher than 1%, then we use the calculated $p_{c,avg}$ as the new guess and repeat the process.

Once the cumulative production is known, the maximum bottomhole pressure, $p_{c,max}$, at the end of the production period can be calculated from Eqs. 39 and 47. The objective of the buildup period is, then, to keep the well shut in long enough for the reservoir pressure at the sandface, p_{ws}, to become equal to or higher than the bottomhole pressure, $p_{c,max}$. Because we approximate the buildup pressures by assuming that the production period was at a constant rate equal to $q(t_p)$ (the last rate prior to shut-in), we calculate an equivalent producing time, $\tilde{t}_p$, by using Eq. 61 and the buildup pressures from Eq. 62. In this process, we start with a shut-in time of $Dt = t - \tilde{t}_p = 0$ (no buildup period) and increase it until the calculated buildup pressure, p_{ws}, becomes equal to or higher than $p_{c,max}$.

We have found that the criterion used to stop the buildup calculations strongly influences the optimization results. After testing several options, we decided to use a logarithmic increment scheme for the shut-in pressures. We start, for example, with an initial increment of 0.01 hr and use this increment until the shut-in time, Dt, becomes 1 hr (of course, if p_{ws} becomes equal to or higher than $p_{c,max}$ before $Dt = 1$ hr, we stop calculations). When Dt, becomes 1 hr, we increase the time increment to 0.1 hr and continue with this increment until $Dt = 10$ hr, at which time we increase the time increment to 1. Although other schemes may be possible, we have found that this scheme to calculate the buildup pressures yielded a stable optimization algorithm without making excessive number of calculations (because of too small time increments) or yielding too large buildup times (because of too large time increments).

The calculation procedures discussed above were considered as independent of each other. In the optimization algorithm, we calculate the optimum production and shut-in times to maximize the cumulative production which makes these two times interrelated. This, however, requires another iterative solution. We start with a producing time of $t_p = 0.1$ hr and calculate Q and $p_{c,max}$ as described above. We start buildup with these values and $Dt = 0$ as discussed above and calculate the buildup pressure, p_{ws}.

If $p_{ws} > p_{c,max}$, this indicates that the reservoir has enough energy to lift the produced liquids so we can go back and increase the producing time, t_p, by using the same logarithmic increment scheme as described above for the buildup calculations. If $p_{ws} < p_{c,max}$, then the buildup pressure is not sufficient to lift the fluids in the tubing so we go back and increase the buildup time for the same producing time value. If $p_{ws} \approx p_{avg}$ without $p_{ws} > p_{c,max}$, where p_{avg} is calculated from Eq. 60 at the end of the previous producing period, this indicates that t_p is too large and the available reservoir energy will not be sufficient to lift the fluids to accumulate for this producing time.

The above iterative scheme normally yields more than one pair of t_p and Dt values because for longer shut-in times, longer producing times may be possible. However, if the objective is to maximize the cumulative production in the long run (for a sequence of production and buildup periods) instead of a single production period, having more flow periods (shorter buildup periods) in a fixed period should be desirable. To find the optimum between longer producing and shorter buildup periods, we assumed in the above optimization scheme that the new pair of the t_p and Dt values are acceptable if they provide at least 5% increase in the cumulative production compared to the previous times.

The optimization algorithm described above was translated into a computational code written in C++ language. The code included a control program to send the opening and closing signals to the wellhead at the times determined by the optimization algorithm. A listing of the computational code along with an example input data file is provided in Appendix D. A fully executable electronic copy is also included in the attachment. The computational code does not require any modification for individual applications. However, the data file needs to be modified for the properties of the individual well and reservoir. Table 2 shows an example of the data set required to run the optimization algorithm.

Table 2 – Example input data set (Marjo well).

Tubing ID	= 1.995 in	c_f	= 0.000002 psi^{-1}
Tubing OD	= 2.375 in	T_{avg}	= 100 °F
Casing ID	= 4.09 in	γ_{liquid}	= 0.834
Tubing Depth	= 6365 ft	γ_{gas}	= 0.720
Tubing ε_D	= 0.00003	μ_{liquid}	= 0.82
d_w	= 6 in	GLR	= 6365 scf/bbl
A	= 160 Acres	C	= 0.0000047 bbl/psi
h_{total}	= 77 ft	S	= 2.5
p_{avg}	= 270 psi	$w_{plunger}$	= 8 lb
p_{line}	= 29.9 psi	$v_{plunger}$	= 15.4 ft/s

Activity 2 - Field-Testing and Validation of the Proposed Method:

Task 2.1 – Building the Electronic Box:

To implement the above-described optimization method, manufacturing an electronic control system to communicate with the wellhead was required. The plunger lift control program is designed to run from a laptop computer with a National Instruments DAQCard-6024E data acquisition board installed. The board is connected with a ribbon cable to a National Instruments SCB-68 connector block. The connector block provides an interface for connections to pressure transducers and the well control box (Fig. 8).

Fig. 8 – The electronic control system for plunger-lift optimization.

The control program uses information provided by the operator to calculate the optimal producing and shut-in times for a plunger lift system. Two threads of execution exist in the program. The first thread measures pressure at a given time interval, currently set at one second. The second thread actually calculates the optimal times and operates the well.

To set up the system, the pressure transducers (Setra) are connected to the wellhead. One transducer is positioned to measure the casing pressure and the other to measure the tubing pressure. Standard pipe fittings and procedures are used in the connections.

The Setra transducers are powered by a 24VDC power supply located in the well control box. The red and black lines are power supply lines, while the green and white lines provide the return voltage to indicate pressure (Figs. 9.A – 9.C). The bare conductor is connected to ground. To minimize soldering, connector blocks are provided, one for each transducer. The connector blocks act as junction between the pressure transducer, the power supply, and the data acquisition connector block.

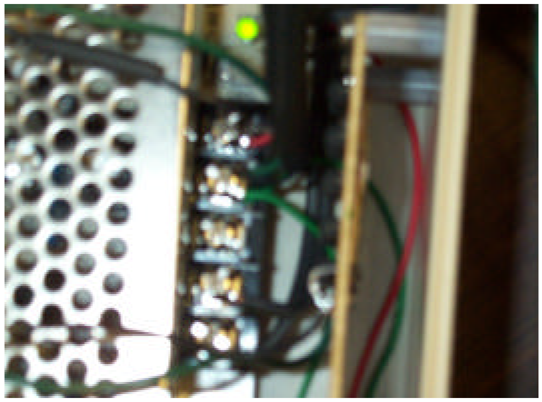

Fig. 9.A – Setra transducer connections.

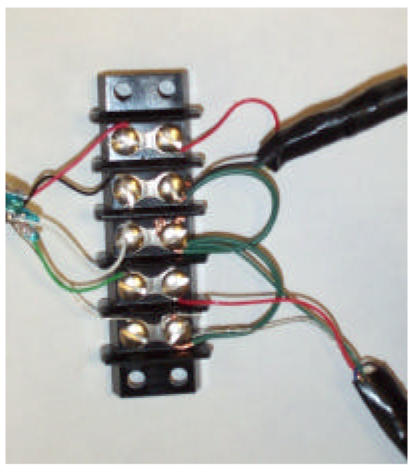

Fig. 9.B – Setra transducer connections.

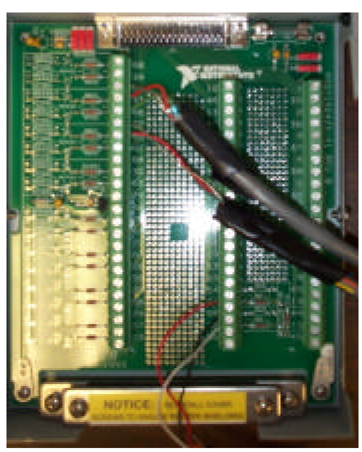

Fig. 9.C – Setra transducer connections.

The solenoid, used in the test wells provided by the Marjo Operating Company, is a 6-volt, three-wire, pulsed operating device. The middle conductor acts as the ground. To operate the solenoid, a 6-volt pulse is applied to the red conductor to open the valve. Applying a voltage pulse, controlled by a circuit, to the white conductor causes the solenoid to close (Fig. 10).

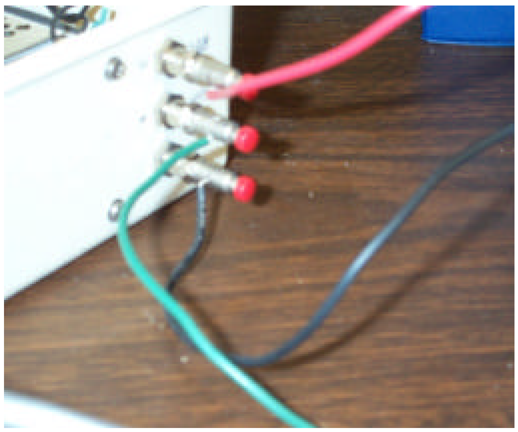

Fig. 10 – Connections between the solenoid and the control circuit.

Once the wiring connections have been made, the data acquisition board is plugged into the connector block with the ribbon cable. The computer and the power supply are also plugged. Because any power fluctuations adversely affect the program and ruin any test in progress, the computer is also plugged into a battery backup.

The computer includes the input data files, the timer program, and the plunger-lift optimization program. The operator at the well site can modify the data files to change or update the input parameters for the optimization algorithm. Starting the computer and the plunger lift program, starts the plunger lift production.

Task 2.2 – Field-Testing of the Method:

The optimization algorithm and the electronic box have been tested by using the field data first and then by applying on a well operated with plunger lift. Testing comprised of three stages: i) testing the algorithm, ii) testing the electronic control system, and iii) field implementation.

i) Testing the algorithm: At the first stage, the algorithm was tested by using the field data shown in Table 2 provided by the Marjo Operating Company. Figure 11 shows the sensitivity of cumulative gas production to reservoir parameters. As indicated by the figure, cumulative gas production is very sensitive to the reservoir parameters supporting the initial motivation of this project to condition the optimization of plunger lift to the reservoir performance.

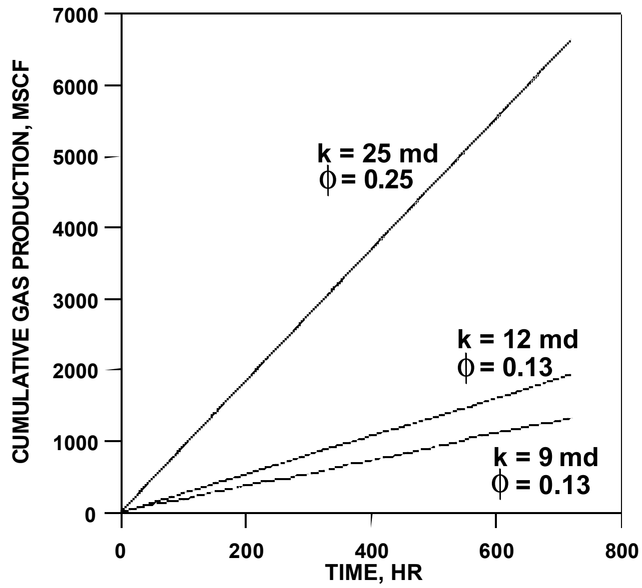

Fig. 11 – Sensitivity of cumulative gas production to reservoir properties.

For the well examined in this test, Marjo Operating Company had provided the average timer clock parameters as 0.4 hr of production and 4.5 hr of shut-in. We tested the corresponding cumulative productions resulting from the timer-clock operation and the optimization algorithm. For both cases, we used the analytical model developed in this project (in one case we forced the production and shut-in times to the values provided by Marjo Operating Company and in the other case, we allowed the optimization algorithm to choose the production and shut-in times). Figure 12 shows the comparison of the cumulative productions for the two cases for a period of one month. The optimization algorithm is shown to double the cumulative production compared with the timer-clock operation. This result confirms the original motivation of this project and indicates that the optimization algorithm has great potential to significantly increase the production from stripper gas wells by improving liquid lifting.

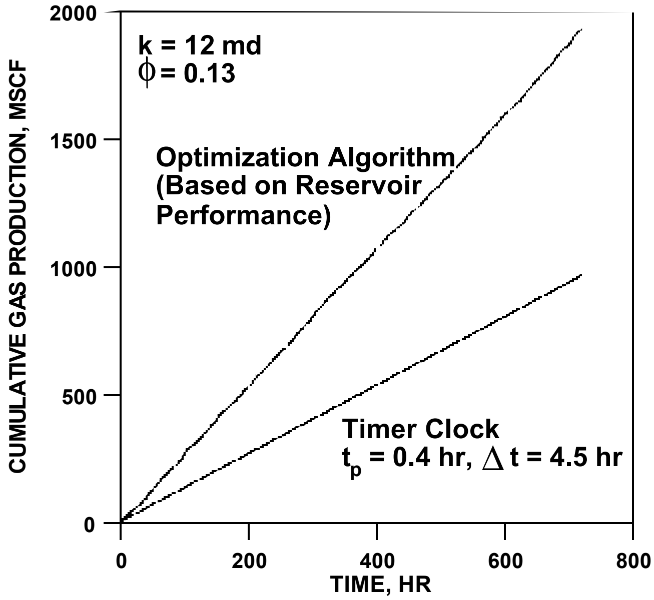

Fig. 12 – Comparison of timer-clock and optimization algorithm performances.

ii) At the second stage, the electronic control system was tested with the solenoid provided by Marjo Operating Company (the solenoid was chosen to be the same kind that is used in the well to be tested at the third stage.) The control system successfully communicated with the solenoid to pass the opening and closing signals in all tests. At the end of these tests, the electronic control system was approved for field-testing.

iii) At the third stage, the electronic control system and the optimization algorithm were implemented in the field at a plunger-lift operated well provided by Marjo Operating Company. Three tests were conducted on three different days. The tests were designed to be run with three different data sets to check the sensitivity to the data and to last eight to twelve hours. The control system failed in all three tests by not closing the well.

The first test appeared to have failed because of a battery shortage and/or improper voltage regulation (as discussed above, the solenoid used the well controls required exactly 6-volt pulse to recognize the opening and closing comments). The failures in the next two tests were attributed to the defects caused by the battery shortage in the first test on the electronic systems. The system was shipped to Colorado School of Mines and checked for any malfunctioning. All components of the electronic control system and the algorithm were tested and found to be working properly.

For this particular field test, the optimization algorithm did not require dynamic input from the well. Using the fixed input parameters, the optimization algorithm determined the opening and closing times of the well and passed this information to the wellhead by the electronic control system. Because the well was opened first but never closed, the optimization algorithm itself was excluded from the list of potential reasons for the failure. The problem appeared to be the communication between the control system and the solenoid under the field conditions. Because the only difference between the office and field tests was the power supply, the control system was sent to the field again with stricter operational regulations in terms of power supply and voltage. However, the winter conditions in the test-well site have not permitted new tests until the due date of the final report. Further tests are planned when the weather conditions permits.

Task 2.3 – Final Report:

Throughout the project, the results have been compiled to construct this final project to be presented to the Stripper Well Consortium. Together with the quarterly reports, this final report documents the development and the results of the project.

CONCLUSIONS

In this project, an algorithm to optimize the production and shut-in times of plunger lift production from stripper gas wells has been developed and tested. In addition, potential of using production data to estimate the reservoir properties required by the optimization algorithm has been investigated. The following conclusions are derived as a result of this project:

1. Based on computer simulations, the optimization algorithm developed in this study based on reservoir performance has the potential to improve plunger lift production from stripper gas wells by 100%.

2. In addition to increasing production in standard operations, the proposed optimization algorithm can be used to automatically adjust the production and shut-in times of the plunger lift when the line pressure changes or fluctuates.

3. The control system required to implement the optimization algorithm in the field can be build under $1000. Therefore, the system should be in the reach of the small producers of stripper gas wells.

4. The implementation of the optimization algorithm does not require any modification of the existing wellheads. This minimizes the cost of implementation and causes minimum distraction to the continuing production.

5. The problems encountered in the field testing of the algorithm appear to be related to inadequate power supply. Further testing is required after correcting the unfavorable operating conditions.

6. Because of the demonstrated high potential of the proposed optimization approach, further research and testing is needed.

7. To commercialize the proposed method, continuous and reliable power supply must be integrated into the design of the electronic control system.

8. The use of decline-type-curve analysis techniques, such as the one developed in this project, has potential to estimate the reservoir properties from production history but accurate measurements of gas rates are required. Current rate measurement tools and practices on stripper gas wells do not usually meet the accuracy requirements for the success of the decline-type-curve analysis.

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LIST OF ACRONYMS AND ABBREVIATIONS

A : area, ft^2, Acres
B : formation volume factor, ft^3/SCF
C : wellbore storage coefficient, bbl-cp/psi^2
c : compressibility, psi^{-1}
d : diameter, ft
f : friction factor
G : gas in place, MSCF
h : formation thickness, ft
I_0 : modified Bessel function of the first kind of order zero
I_1 : modified Bessel function of the first kind of order one
J : productivity index, bbl/psi
K : gas friction term, ft
K_0 : modified Bessel function of the second kind of order zero
K_1 : modified Bessel function of the second kind of order one
k : permeability, md
L : horizontal well length, ft, Laplace transform
m : pseudopressure, psi^2/cp
N_{Re} : Reynolds number
p : pressure, psi
Q : cumulative production, bbl
q : production rate, bbl/d
r : radius, ft
S : Skin factor
s : Laplace transform parameter
T : temperature, ºR
t : time, d, hr
V : volume, ft^3
Z : gas compressibility factor

Greek letters:

g : specific gravity
D : difference, shut in
m : viscosity
h : transmissibility coeffcient
f : porosity
e : surface roughness

Subscripts and superscripts

: average, Laplace transform of
~ : modified

a	: annulus, pseudoequivalent
avg	: average
c	: casing
cp	: constant pressure
D	: dimensionless, tubing depth
e	: external, equivalent
i	: initial
l	: liquid
max	: maximum
min	: minimum
M.P.	: match point
p	: producing
w	: wellbore
wf	: flowing wellbore
ws	: shut in
t	: total, tubing
ur	: unit rate
0	: datum
-1	: inverse

APPENDIX A

ANALYTICAL SOLUTIONS FOR VERTICAL AND HORIZONTAL WELLS

In this appendix we present the analytical solutions for vertical and horizontal wells in cylindrical homogeneous reservoirs.

A.1. Analytical Solutions for Unfractured Vertical Wells in Cylindrical Reservoirs

Dimensionless pressure for fluid flow in a in a cylindrical porous medium of dimensionless radius r_{eD} is given in the Laplace transform domain by[24]

$$\overline{p}_D(r_D,s)=\frac{K_1\left(\sqrt{s}r_{eD}\right)I_0\left(\sqrt{s}r_D\right)+I_1\left(\sqrt{s}r_{eD}\right)K_0\left(\sqrt{s}r_D\right)}{s^{3/2}\left[I_1\left(\sqrt{s}r_{eD}\right)K_1\left(\sqrt{s}\right)+K_1\left(\sqrt{s}r_{eD}\right)I_1\left(\sqrt{s}\right)\right]}. \tag{A-1}$$

In Eq. A-1, the overbar symbol indicates the Laplace transform of the function (that is, $\overline{p}_D$, is the Laplace transform of p_D), $I_0, K_0, I_1,$ and K_1 are the modified Bessel's functions, s is the Laplace transform parameter, and the dimensionless radial distance r_D is defined by

$$r_D=\frac{r}{r_w}. \tag{A-2}$$

van Everdingen and Hurst[24] obtained the following analytical inversion of Eq. A-1 by using the inversion integral:

$$\begin{aligned}p_D(r_D,t_D)=&\left\{\frac{2}{r_{eD}^2-1}\left(t_D-\frac{r_D^2}{4}\right)-\frac{r_{eD}^2}{r_{eD}^2-1}\ln r_D\right.\\&-\frac{1}{4\left(r_{eD}^2-1\right)^2}\left(3r_{eD}^4-4r_{eD}^4\ln r_{eD}-2r_{eD}^2-1\right)\\&\left.+p\sum_{n=1}^{\infty}\frac{J_1^2(b_nr_{eD})\left[J_1(b_n)Y_0(b_nr_D)-Y_1(b_n)J_0(b_nr_D)\right]}{b_n\left[J_1^2(b_nr_{eD})-J_1^2(b_n)\right]}exp\left(-b_n^2t_D\right)\right\}\end{aligned}. \tag{A-3}$$

In Eq. A-3, b_1, b_2, etc. are the roots of

$$Y_1(b_n)J_1(b_nr_{eD})-J_1(b_n)Y_1(b_nr_{eD})=0, \tag{A-4}$$

and, J_0, Y_0, J_1, and Y_1 are the Bessel's functions.

The solution given in Eq. A-1 may also be inverted numerically by using the Stehfest algorithm.[17] This algorithm obtains an approximate inverse, $p_a(T)$, of the Laplace domain function, $\overline{p}(s)$, at time $t = T$ by

$$p_a(T) = \frac{ln\,2}{T}\sum_{i=1}^{N} V_i\,\overline{p}(s)_{s=i\frac{ln\,2}{T}}\,, \tag{A-5}$$

where

$$V_i = (-1)^{(N/2)+i}\sum_{k=(i+1)/2}^{min(i,N/2)} \frac{k^{N/2}(2k)!}{[(N/2)-k]!\,k!(k\text{-}1)!(i\text{-}k)!(2k\text{-}i)!}\,, \tag{A-6}$$

and N is an even integer. Theoretically, the accuracy of the inversion should increase as N increases but the accuracy becomes less for large N because of round-off errors. Therefor, the optimum value of N needs to be determined by trial and error ($6 \le N \le 18$ is a common range for transient flow problems).

In this project, we used Stehfest's algorithm to develop the decline type curves. To compute the dimensionless wellbore pressures, p_{wD}, we set $r_D = 1$ in Eq. A-1. Note that the dimensionless pressure solution given by Eq. A-1 corresponds to production at a constant rate. To obtain the dimensionless flow rates, q_D, as a result of constant pressure production, we used the constant rate production solution given by Eq. A-1 with the following Laplace transform property:

$$\overline{q}_D\,\overline{p}_{wD} = \frac{1}{s^2}\,, \tag{A-7}$$

A.2. Analytical Solutions for Horizontal Wells in Cylindrical Reservoirs

Ozkan and Raghavan[25] have shown that the wellbore pressures of horizontal wells in a closed cylindrical reservoir can be computed from the following expression:

$$\overline{p}_{wD}(|x_D| \le 1, s) = \frac{1}{2s^{3/2}}\left[\int_0^{\sqrt{s}(1+x_D)} K_0(x)dx + \int_0^{\sqrt{s}(1-x_D)} K_0(x)dx\right] + \overline{F}(x_D, z_D, z_{wD}, L_D) \tag{A-8}$$

where

$$\overline{F}(x_D, z_D, z_{wD}, L_D) = \frac{1}{s}\sum_{n=1}^{\infty}\frac{\cos n\pi z_D \cos n\pi z_{wD}}{\varepsilon_n}$$
$$\left[\int_0^{\sqrt{s+n^2\pi^2L_D^2}(1+x_D)} K_0(\xi)d\xi + \int_0^{\sqrt{s+n^2\pi^2L_D^2}(1-x_D)} K_0(\xi)d\xi\right] \quad \text{(A-9)}$$

In Eqs. A-8 and A-9, the dimensionless variables are defined based on the half-length of the horizontal well, $L_h/2$, as follows:

$$p_D = \frac{k\,h}{141.2qB\mu}(p_i - p), \quad \text{(A-10)}$$

$$t_D = \frac{2.637\times10^{-4}kt}{\phi c_t\mu(L_h/2)^2}, \quad \text{(A-11)}$$

$$L_D = \frac{L_h}{2h}\sqrt{\frac{k_z}{k}}, \quad \text{(A-12)}$$

$$z_D = \frac{z}{h}, \quad \text{(A-13)}$$

$$r_{wD} = \frac{r_{w,eq}}{h}, \quad \text{(A-14)}$$

and

$$x_D = \frac{2x}{L_h}\sqrt{\frac{k_x}{k}}. \quad \text{(A-15)}$$

In Eqs. 12.3.1 and 12.3.2, k represents the geometric average of the principal permeabilities, k_x, k_y, and k_z that are assumed to be in the directions of the coordinate axes; that is, $k = \sqrt[3]{k_x k_y k_z}$. In Eq. A-14, $r_{w,eq}$ denotes the equivalent wellbore radius for an anisotropic medium and may be obtained from[26]

$$r_{w,eq} = 0.5 r_w \left[\left(k_y / k_z \right)^{0.25} + \left(k_z / k_y \right)^{0.25} \right]. \tag{A-16}$$

The dimensionless variable x_D in Eqs. A-8 and A-9 determines the point to calculate the pressure along the well. For long horizontal wells, $x_D = 0.732$ yields the approximate response of an infinite-conductivity horizontal well.[27]

APPENDIX B

DERIVATION OF THE COEFFICIENT OF GAS STORAGE IN THE WELLBORE

In this appendix we summarize the derivation of the annulus gas storage coefficient for the buildup period of a plunger lift operation. It has been shown that the mass balance in a wellbore yields[28]

$$q_{sf} = q - q_{wb}\,, \tag{B-1}$$

where q_{wb} is the flow rate due to production of the fluid stored in the wellbore and q_{sf} and q denote, respectively, the sandface and surface production rates. The wellbore flow rate is given by

$$1000\,q_{wb}\,\rho_{sc} = -(24)(5.615)V_{wb}\,\frac{d\overline{\rho}_{wb}}{dt}\,. \tag{B-2}$$

In Eq. B-2,

q_{wb} : gas flow rate due to storage, $MSCFD$,

t : time, hr,

$\overline{\rho}_{wb}$: average density of the fluid in the wellbore, lb_m / ft^3,

ρ_{sc} : density of the fluid at standard conditions, lb_m / ft^3, and

V_{wb} : volume of the fluid stored in the wellbore, bbl.

Using

$$\frac{d\overline{\rho}_{wb}}{dt} = \frac{d\overline{\rho}_{wb}}{d\overline{p}_{wb}}\frac{d\overline{p}_{wb}}{dt} = \overline{c}_{wb}\,\overline{\rho}_{wb}\,\frac{d\overline{p}_{wb}}{dt} \tag{B-3}$$

we can write Eq. B-3 as follows:

$$q_{wb}\,\frac{\rho_{sc}}{\overline{\rho}_{wb}} = -(24)\left(5.615\times10^{-3}\right)\overline{c}_{wb}V_{wb}\,\frac{d\overline{p}_{wb}}{dt} \tag{B-4}$$

For the shut-in period of plunger lift, the fluid is stored in the annulus between the casing and tubing and may be assumed as single-phase gas. Thus,

$$V_{wb} = \left(A_c - A_t\right)h\,, \tag{B-5}$$

where A_c and A_t are the cross-sectional areas of the casing and tubing, respectively, and h is the formation thickness. From the gas equation of state, we can write[28]

$$B_g = \frac{\rho_{sc}}{\overline{\rho}_{wb}} = \frac{\overline{Z}_{wb}\overline{T}_{wb}\,p_{sc}}{\overline{p}_{wb}T_{sc}} = 0.02827\,\frac{\overline{Z}_{wb}\overline{T}_{wb}}{\overline{p}_{wb}}\,, \tag{B-6}$$

where we have used $p_{sc} = 14.7 psi$ and $T_{sc} = 520^\circ R$. Substituting Eqs. B-5 and B-6 into Eq. B-4, we obtain

$$q_{wb} = -24 \frac{\overline{p}_{wb} \overline{c}_{wb} \left(A_c - A_t\right) h}{5.035 \overline{Z}_{wb} \overline{T}_{wb}} \frac{d\overline{p}_{wb}}{dt}. \tag{B-7}$$

Because

$$\frac{d\overline{p}_{wb}}{dt} = \frac{\overline{m}_{wb} \overline{Z}_{wb}}{2\overline{p}_{wb}} \frac{d\overline{m}_{wb}}{dt} \tag{B-8}$$

Eq. B-7 may be written as

$$q_{wb} = -24 \frac{\overline{m}_{wb} \overline{c}_{wb} \left(A_c - A_t\right) h}{10.07 \overline{T}_{wb}} \frac{d\overline{m}_{wb}}{dt}. \tag{B-9}$$

Thus, if we define a wellbore storage coefficient by

$$C = \frac{\overline{m}_{wb} \overline{c}_{wb} \left(A_c - A_t\right) h}{10.07 \overline{T}_{wb}}, \tag{B-10}$$

then, we can write Eq. B-9 as follows:

$$q_{wb} = -24 C \frac{d\overline{m}_{wb}}{dt}. \tag{B-11}$$

APPENDIX C

NUMERICAL INVERSION OF THE BUILDUP SOLUTION GIVEN BY EQ. 62

This appendix summarizes the numerical inversion procedure used to calculate the pressure buildup responses from Laplace domain solution given by Eq. 62 in the text. In Petroleum Engineering, the numerical inversion algorithm due to Stehfest[17] is commonly used to compute the real time values of the solutions in the Laplace transform domain. In Eq. 62, discontinuity of the production caused by the shut-in at $t = \tilde{t}_p$ poses difficulties in the numerical inversion.

The discontinuity at $t = \tilde{t}_p$ is represented by the $e^{-s\tilde{t}_p}$ terms in Eq. 62. Chen and Raghavan[23] have suggested that for the numerical inversion of a function in the form of $\bar{f}(s)\left(1 - e^{-s\tilde{t}_p}\right)$ by using Stehfest's algorithm, the following formula should be useful:

$$L^{-1}\left\{\bar{f}(s)\left(1 - e^{-s\tilde{t}_p}\right)\right\}_t = L^{-1}\{\bar{f}(s)\}_t - L^{-1}\{\bar{f}(s)\}_{t-\tilde{t}_p} . \tag{C-1}$$

In Eq. C-1, L^{-1} denotes the inverse Laplace transformation. The first term in the right hand side of Eq. C-1 is inverted at time t and the second term is considered only when $t > \tilde{t}_p$ and is inverted at $t - \tilde{t}_p$.

Because our interest in this project is to compute the pressure buildup responses, we need to evaluate Eq. 62 for $t \geq \tilde{t}_p$. Then using Eq. C-1, the numerical inversion formula for Eq. 62 is written as follows:

$$L^{-1}\{D\overline{m}_{ws}\} = L^{-1}\left\{\frac{D\overline{m}_{wf,ur}}{s\left(1 + 24Cs^2 D\overline{m}_{wf,ur}\right)}\right\}_t - L^{-1}\left\{\frac{D\overline{m}_{wf,ur}}{s\left(1 + 24Cs^2 D\overline{m}_{wf,ur}\right)}\right\}_{t-\tilde{t}_p} \tag{C-2}$$

In practice, Eq. C-2 is evaluated in two steps. In the first step, the first term in the right hand side of Eq. C-2 is inverted to the real-time domain at time t and the second term is inverted at time $t - \tilde{t}_p$ separately. In the second step, the difference between the numerical inversions of the first and second terms in the right hand side of Eq. C-2 is calculated as the value of Dm_{ws} in the real time domain.

APPENDIX D

COMPUTATIONAL CODE FOR THE OPTIMIZATION ALGORITHM

This appendix presents a listing of the computational code for the plunger lift optimization algorithm in C++ and an example input data file. An executable copy of the program is also provided in the attachment of this report.

A. Optimization Algorithm:

```
//
//  PLOP Version 1.0
//

/*
 * Includes:
 */
#include <conio.h>
#include <stdio.h>
#include <windows.h>

#include "nidaqex.h"
#include "PLOP.h"



/* Global Variable */
FILE *pressFP;    //File pointer for pressures

/* This function is a thread which reads and records voltage
 * from the transducer.  Modified from Microsoft and NI sample codes.
 */
DWORD WINAPI ReadPressFunc( LPVOID lpParam )
{

     /*
    * Local Variable Declarations:
    */
```

```
i16 iStatus = 0;
i16 iRetVal = 0;
i16 iDevice = 1;
i16 iChan = 1;
i16 iGain = 1;
f64 dVoltage = 0.0;
i16 iIgnoreWarning = 0;

	int i;
	SYSTEMTIME locoTime;
	double dPressure1, dPressure2;

//	for (i=0;i<10;i++) {
	for (;;) {

		GetLocalTime(&locoTime);		// get current time

		iChan = 1;
	   iStatus = AI_VRead(iDevice, iChan, iGain, &dVoltage);

		iRetVal = NIDAQErrorHandler(iStatus, "AI_VRead", iIgnoreWarning);

		dPressure1 = (dVoltage-0.11)*200.;		// convert to pressure



		iChan = 2;
		iStatus = AI_VRead(iDevice, iChan, iGain, &dVoltage);

		iRetVal = NIDAQErrorHandler(iStatus, "AI_VRead", iIgnoreWarning);

		dPressure2 = (dVoltage-0.11)*200.;		// convert to pressure

	// Build a string showing the date, time, and pressure measurements
		fprintf(pressFP, "%02d/%02d/%d  %02d:%02d:%02d  PT1 = %lf PT2 = %lf\n",
			locoTime.wDay, locoTime.wMonth, locoTime.wYear,
			locoTime.wHour, locoTime.wMinute, locoTime.wSecond,
			dPressure1, dPressure2);
```

```
                Sleep(1000);  //Measurement approx. every second

        }

}

const long HTMS = 3600000;

void cal_production_data2(double &TP, double &DT){

return;
}

void OpenWell(double TP)
{
        printf("Opening the well for %lf hours.\n", TP);
        fprintf(pressFP,"Opening the well for %lf hours.\n", TP);
        /*
         * This function works by raising the voltage for 500 ms on DAC1
         */

    /*
     * Local Variable Declarations:
     */

    i16 iStatus = 0;
    i16 iRetVal = 0;
    i16 iDevice = 1;
    i16 iChan = 1;
    f64 dVoltage1 = 5.0;
    f64 dVoltage2 = 0.0;
    i16 iIgnoreWarning = 0;

        /* First output 5.0 volts to start pulse. */
    iStatus = AO_VWrite(iDevice, iChan, dVoltage1);
```

```
   iRetVal = NIDAQErrorHandler(iStatus, "AO_VWrite", iIgnoreWarning);

     Sleep(500);

   /* Then output 0.0 volts to end pulse. */
   iStatus = AO_VWrite(iDevice, iChan, dVoltage2);

   iRetVal = NIDAQErrorHandler(iStatus, "AO_VWrite", iIgnoreWarning);

}

void CloseWell(double DT)
{
     printf("Shut-in the well for %lf hours.\n", DT);
     fprintf(pressFP,"Shut-in the well for %lf hours.\n", DT);
     /*
      * This function works by raising the voltage for 500 ms on DAC0
      */

   /*
    * Local Variable Declarations:
    */

   i16 iStatus = 0;
   i16 iRetVal = 0;
   i16 iDevice = 1;
   i16 iChan = 0;
   f64 dVoltage1 = 5.0;
   f64 dVoltage2 = 0.0;
   i16 iIgnoreWarning = 0;

     /* First output 5.0 volts to start pulse. */
   iStatus = AO_VWrite(iDevice, iChan, dVoltage1);

   iRetVal = NIDAQErrorHandler(iStatus, "AO_VWrite", iIgnoreWarning);

     Sleep(500);
```

```
   /* Then output 0.0 volts to end pulse. */
   iStatus = AO_VWrite(iDevice, iChan, dVoltage2);

   iRetVal = NIDAQErrorHandler(iStatus, "AO_VWrite", iIgnoreWarning);

}

/* This function is a thread which operates the well based on values
 * calculated from cal_production_data
 */
DWORD WINAPI OperateWellFunc( LPVOID lpParam )
{

	double TP,DT;
	int count = 1;

	for(;;) {
			printf("Run number %d.\n",count++);
			//Calculates DP, TP and anything else
//			cal_production_data(TP, DT);
// What is the output??????????????????? Hours?? HTMS = 3600000
			cal_production_data(TP, DT);
			printf("TP= %lf hours, DT= %lf hours.\n",TP,DT);
			//open well function
			OpenWell(TP);
			//Sleep (TP hrs)
			Sleep(TP*HTMS);
			//Close well function
			CloseWell(DT);
			//Sleep (DT hrs)
			Sleep(DT*HTMS);
			printf("\n");
	}
}

int main(int argc, char* argv[])
```

```
{

   DWORD dwThreadId1, dwThreadId2, dwThrdParam = 1;
   HANDLE hThread1, hThread2;
   char szMsg[80];

   printf("Hit any key to end program....\n");

     /* Open a file to put pressure into */
     pressFP = fopen("test1.txt","a");



   hThread1 = CreateThread(
       NULL,                  // no security attributes
       0,                     // use default stack size
       ReadPressFunc,         // thread function
       &dwThrdParam,          // argument to thread function
       0,                     // use default creation flags
       &dwThreadId1);         // returns the thread identifier

  // Check the return value for success.

   if (hThread1 == NULL)
   {
     wsprintf( szMsg, "CreateThread (ReadPressFunc) failed." );
     MessageBox( NULL, szMsg, "main", MB_OK );
        return 0;
   }

   hThread2 = CreateThread(
       NULL,                  // no security attributes
       0,                     // use default stack size
       OperateWellFunc,       // thread function
       &dwThrdParam,          // argument to thread function
       0,                     // use default creation flags
       &dwThreadId2);         // returns the thread identifier
```

```
    // Check the return value for success.

    if (hThread2 == NULL)
    {
      wsprintf( szMsg, "CreateThread (OperateWellFunc) failed." );
      MessageBox( NULL, szMsg, "main", MB_OK );
        return 0;
    }

       //Wait for a character to be pressed.
    _getch();

       CloseHandle( hThread1 );
       CloseHandle( hThread2 );

       /* Close file */
       fclose(pressFP);

       return (0);
  }

/* End of program */

  //
  //          FILE PLOP.h  10/31/2002
  //
  //  PROGRAM OPTIMIZES THE PRODUCTION AND BUILD-UP TIMES OF A
  //    PLUNGER-LIFT SYSTEM PRODUCING GAS IN THE PRESENCE OF A
  //    LIQUID COLUMN IN THE WELLBORE.
  //

  #include <iostream>
  #include <iomanip>
  #include <fstream>
  #include <cmath>
  #include <cstdlib>
  using namespace std;
```

```
const float HRS = 216000;

double FC(double, double);

void STEHFESTV(double [], int);

void PBUP(double &, int,double [],double, double, double, double,
          double, double, double, double, double, double, double, int);

double PU(double, double, double, double, double, double, int, double,
          double, double, double);

void QCPAV (double &, double &, double &, double &, double &, double &, int &,
            double &, int, double [], double, double, double, double, double,
            double, double, double, double, double, int, double, double, double,
            double, double, double, double, double, double, double, double,
            double, double, double, double, double, double [], double [], int);

void PROP(double &, double &, double, double, double, int);

void CPROD(double &, double &, int, double [], double, double, double, double, double, int);

void PCAVSUB(double &, double &, double, double, double, int, double, double, double,
             double, double, double, double, double, double, double, double, double,
             double, double, double);

double Q(double, double, double, double, double, int);

double BESSK1(double);

double BESSI1(double);

double BESSK0(double);

double BESSI0(double);

double ZFAC (double, double, double, int, int);
```

```
double GASVIS (double, double, double, int);

void dranchukcorr(double&, double, double);

void hallyarbcorr(double&, double, double);

void standingcorr(double&, double, double);

void gopalcorr(double&, double, double);

double FLAGR (double [], double [], double, int, int, int);

double YEST(double [],double [], int, int, double);

  double D, H,P, T, X;
    double TID, TOD, CID, WP, PTMIN, TIME, QGCTOT, PSTART, PSPIN;
    int MCODE, ICOUNT, N, IERR, NPRES, IFR;
    double SGL, SGG, VPAV, TAV, GLR, VISL, EPSD, DPAVG, PI;
    double PIN, PERM, PHI, CF, CWS, SK, RW, RE, PMIN, PMAX, ETA, DMWS;
    double AT, AA, PP, BL, P1H, RHOL, REL, FL, WM, SUMP, CG, VISG, PCAV, TPCP;
  double PCAVN, PCMAXN, PCMAX, DPSPCN, QGCT, TT, CH1, CH2;
    double TPT, DTT, PCAVT, PCMAXT, PWS, PWST, QTP, QTPT, QTPP, PSPWSN, PWSN;
    double DQCN, QGC, PCAVO;
    double DPN, TN, TPN, DTN;
    double QGCN, QTPN ;


//*&^*^$&&#&%^%$^&&%$#%#^&%^#&$^*&^*%^&*&*^%&^&(&%*(&%(%#&$^%$#^&
//%$#^#%#$%^&$^&^&%^&*^&*%^*^%$#W%$^@@^@^$%^@^@%^%^$%^$%^%^@^%%%
%
//&*^%&)&)%%#(&%#(&#(&(&(%(%#&)#^(%@%^@(^$(*^%*%^$%^&^@*(^@(^$@))

void cal_production_data(double &TP, double &DT){

//
ifstream infil ("PLOdat3M.text", ios::in);
```

```
ofstream outfil ("PLOout1.text", ios::out);

const int arraySize1 = 51;
double V[arraySize1]={0.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.};
const int arraySize2 = 51;
double PRE[arraySize2]={0.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.};
double PSP[arraySize2]={0.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.};
double ZZ[arraySize2]={0.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.};
double VIS[arraySize2]={0.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,
                                    1.,1.,1.,1.,1.,1.,1.,1.,1.,1.,1.};


//    ************************************************************
//    *         READ THE CONSTANT INPUT DATA (TABLE 1)          *
//    ************************************************************
   infil >> TID >> TOD >> CID >> D >> WP >> PTMIN;
     infil>>SGL>>SGG>>VPAV>>TAV>>GLR>>VISL;
     infil>>EPSD;
```

```
    infil>>PIN>>PERM>>PHI>>CF>>CWS>>SK>>RW>>RE>>H;
    infil>>PMIN>>PMAX>>NPRES>>N;
//  ***************************************************************
//  *     CALCULATE THE CONSTANT INPUT DATA (TABLE 2)          *
//  ***************************************************************

    MCODE=1;
    ICOUNT=0;
    PI=4*atan(1);
    AT=PI*TID*TID/4/144;
    AA=PI*(CID*CID-TOD*TOD)/4/144;
    PP=WP/AT/144;
    BL=5.615/AT;
    P1H=0.433*SGL*BL;
    RHOL=0.433*SGL;
    REL=3.527*RHOL*VPAV*TID/VISL;
    FL=FC(REL,EPSD);
    WM=28.97*SGG;
//  ***************************************************************
//  *   CALCULATE THE COEFFICIENTS OF THE STEHFEST ALGORITHM   *
//  ***************************************************************
    STEHFESTV (V,N);
//  ***************************************************************
//  *       INITIALIZE TIME AND CUMULATIVE PRODUCTION                 *
//  ***************************************************************
    TIME=0;
    QGCTOT=0;
//  ***************************************************************
//  *        CONSTRUCT THE PSEUDOPRESSURE TABLE            *
//  ***************************************************************
  DPAVG=(PMAX-PMIN)/(NPRES-1.);
  PSTART=PMIN;
    PRE[0]=0.;
    PSP[0]=0.;
    ZZ[0]=0.;
    VIS[0]=0.;
  SUMP=0.;
```

```
for(int i=0; i < NPRES+1; ++i) {
        int ic=i+1;
        PRE[ic]=PSTART;
        ZZ[ic]=ZFAC(TAV,PSTART,SGG,MCODE,IERR);
        VIS[ic]=GASVIS(TAV,SGG,PSTART,IERR);
        if (ic==1)
                SUMP=SUMP+(PRE[ic]/VIS[ic]/ZZ[ic])*PRE[ic];
        else
                SUMP=SUMP+(PRE[ic-1]/VIS[ic-1]/ZZ[ic-1]+PRE[ic]/VIS[ic]/ZZ[ic])
                *(PRE[ic]-PRE[ic-1]);

        PSP[ic]=SUMP;
        PSTART=PSTART+DPAVG;
}

//  ****************************************************************
//  *CALCULATE THE PSEUDO INITIAL PRESSURE FOR THE FIRST         *
// *PRODUCTION CYCLE
                *
//  ****************************************************************
    PSPIN=FLAGR(PRE,PSP,PIN,1,NPRES,IERR);
//  ****************************************************************
//  *CALCULATE THE FIRST GUESS FOR THE CONSTANT WELLBORE PRESSURE  *
// *BY ASSUMING THAT P-INITIAL CORRESPONDS TO PC-MAX.          *
// ****************************************************************
    PCAV=PIN*(2*AA+AT)/2/(AA+AT);
// ****************************************************************
//  *CALCULATE TP AND DT TO OPTIMIZE THE PRODUCTION FOR A GIVEN   *
// *CYCLE. REPEAT CALCULATIONS UNTIL A STOPPING TIME                    *
                                                  *
//  ****************************************************************
//869048649086-860-86-3863850-809380383-    //while (TIME <= 720.){

// ****************************************************************
//  *PRODUCING TIME (DRAWDOWN AT A CONSTANT PRESSURE) CALCULATIONS *
                                              *
//  ****************************************************************
```

```
                QGCT=1E-7;
                TT=0.1;
                TPCP=0.1;
                CH1=0.01;
    // ****************************************************************
    //    *CALCULATE THE CUMULATIVE PRODUCTION AND RATE (ASSUMING
*
    //  *PRODUCTION AT CONSTANT PRESSURE PWF=PCAV) UNTIL PRESSURE      *
    //  *DROPS BELOW PCMAX
*
    //    ****************************************************************

    start1:

                QCPAV(QGCN,QTPN,PCMAXN,PCAVN,CG,ETA,IFR,DPSPCN,N,V,
                         SK,RW,RE,PERM,PHI,H,VISG,TAV,PCAV,SGG,MCODE,WM,
                              TID,EPSD,TPCP,GLR,SGL,FL,VPAV,BL,PP,PTMIN,P1H,
                              AT,AA,D,PSPIN,PRE,PSP,NPRES);
    //    **************************************************************
    //  *SHUT-IN TIME (BUILDUP) CALCULATIONS
*
    //    **************************************************************
    //    *COMPUTE THE EQUIVALENT CONSTANT RATE PRODUCING TIME TO BE       *
    //  *USED IN PRESSURE BUILDUP CALCULATIONS (PRESSURE BUILDUP     *
    //    *IS ASSUMED TO FOLLOW A PRODUCTION PERIOD OF EQUIVALENT              *
    //  *PRODUCING TIME AT A CONSTANT RATE OF QTP EQUAL TO THE LAST  *
    //  *RATE AT THE END OF THE PRODUCTION PERIOD)
*
    // **************************************************************
                 TPN=24.*QGCN/QTPN;
    //    **************************************************************
    //  *COMPUTE THE BUILDUP PRESSURES
         *
    //    **************************************************************
                     DTN=0;
                     CH2=0.01;

    start2:
```

```
                    TN=TPN+DTN;
            PBUP(DMWS,N,V,TPN,TN,QTPN,TAV,CWS,SK,RW,RE,H,PERM,ETA,IFR);
//
                    if (DMWS <= 0){
//                          cout<<"***DMWS<=0***"<<endl;
                            T=TT;
                            TP=TPT;
                            DT=DTT;
                            PCAV=PCAVT;
                            PCMAX=PCMAXT;
                            PWS=PWST;
                            QTP=QTPT;
                            QGC=QGCT;
                            PSPIN=PSPIN-
2.*1422.*(TAV+460.)*ETA*QGC/24./RE/RE/PERM/H;
                            PIN=FLAGR(PSP,PRE,PSPIN,1,NPRES,IERR);
                            goto end;
                    }
                    PSPWSN=PSPIN-DMWS;
                    PWSN=FLAGR(PSP,PRE,PSPWSN,1,NPRES,IERR);
                    DPN=PWSN-PCMAXN;
//                  cout<<"DPN="<<DPN<<"DTN="<<DTN<<"TPN="<<TPN<<endl;
//   ***************************************************************
//  *CHECK TO SEE IF PRODUCING TIME IS TOO LONG
*
//  *(PCMAX SHOULD BE LESS THAN PWS)
*
//  *IF YES, REDUCE PRODUCING TIME
       *
// ****************************************************************
                    if(DPN >= 0.){
                            if(DTN == 0.){
                                    if(TPCP >= CH1*10.)
                                            CH1=CH1*10.;
                                    TPCP=TPCP+0.1*CH1;
                                    goto start1;
                            }
                            else{
```

```
                    DQCN=100.*(QGCN-QGCT)/QGCN;
                        if(DQCN >= 1.){
                            TT=TN;
                            TPT=TPN;
                            DTT=DTN;
                            PCAVT=PCAVN;
                            PCMAXT=PCMAXN;
                            PWST=PWSN;
                            QTPT=QTPN;
                            QGCT=QGCN;
                        }
                        if(TPCP >= CH1*10.)
                            CH1=CH1*10.;
                        TPCP=TPCP+0.1*CH1;
                        goto start1;
                }
            }
            else{
                if(DTN >= CH2*10.)
                    CH2=CH2*10.;
                DTN=DTN+0.1*CH2;
                goto start2;
            }

end:
;
//  ***************************************************************
//  *OUTPUT RESULTS
                     *
//  ***************************************************************
    /*                      TIME=TIME+TP;
                            QGCTOT=QGCTOT+QGC;
                            QTPP=QTP;
                            cout<<"TIME="<<TIME<<"          "<<"QGCTOT="<<QGCTOT<<"
"<<"QTPP="<<QTPP<<endl;

outfil<<setw(10)<<TIME<<setw(10)<<QGCTOT<<setw(10)<<QTPP<<endl;
                            TIME=TIME+DT;
```

```
                        QTPP=0;
                        cout    <<"TIME="<<TIME<<"        "<<"QGCTOT="<<QGCTOT<<"
"<<"QTPP="<<QTPP<<endl;

outfil<<setw(10)<<TIME<<setw(10)<<QGCTOT<<setw(10)<<QTPP<<endl;
   //
                        cout<<"DT="<<DT<<"   "<<"TP="<<TP<<endl;
                        cout
<<"*************************************************"<<endl;
   */
   //

   //
   }

   //    ***********************************************************
   //    *                  SUBROUTINE PBUP                                    *
   //    *
                        *
   //    *PROGRAM COMPUTES BUILDUP PRESSURES FOLLOWING CONSTANT              *
   //    *PRESSURE PRODUCTION USING LAPLACE DOMAIN SOLUTIONS AND
*
   //    *NUMERICAL INVERSION
                  *
   //    ***********************************************************
   void PBUP(double &DMWS, int N,double V[],double TP, double T, double QTP, double TAV,
               double CWS, double SK, double RW, double RE, double H,
               double PERM, double ETA, int IFR){

      double A, ARG;
     double DLOGTW=.6931471805599453;
      double FREG, FA1, FA2, TTP;
      double TTPAD;
      int IFR1;

      PI=4*atan(1);
   //
   //
   //
```

```
FA1=0.;
A=DLOGTW/T;
  for (int I=0; I<N; ++I){
        ARG=A*(I+1);
   FA1=FA1+V[I+1]*PU(ARG,RE,RW,CWS,SK,ETA,IFR,PERM,H,TAV,QTP);
  }
//
  FA1=A*FA1;
  if(fabs(FA1) <= pow(10,-38)){
        FA1=0.;
   }
//
        TTP=T-TP;
//
  if(TTP > 0){
        TTPAD=ETA*TTP/PI/RE/RE;
        IFR1=0;
        FREG=TTPAD-0.1;
        if(FREG >=0 )
             IFR1=1;
//
   FA2=0;
        A=DLOGTW/TTP;
    for (int I=0; I<N+1; ++I){
         ARG=A*(I+1);
    FA2=FA2+V[I+1]*PU(ARG,RE,RW,CWS,SK,ETA,IFR,PERM,H,TAV,QTP);
        }

   FA2=A*FA2;
   if(fabs(FA2) <= pow(10,-38)){
         FA2=0.;
        }
  }
//
  else
   FA2=0.;
//
```

```
    DMWS=FA1-FA2;
      if (DMWS <= 0.)
              DMWS=0.;
//
      }
//    ************************************************************
double PU (double S, double RE, double RW, double CWS, double SK,
            double ETA, int IFR, double PERM, double H, double TAV, double QTP){
//
      double P, ARG1, ARG2, TOP, BOT, PU;
//
    ARG1=sqrt(S/ETA)*RW;
      ARG2=sqrt(S/ETA)*RE;
//
      if (IFR == 0)
      P=BESSK0(ARG1)/S/ARG1/BESSK1(ARG1)+SK/S;
      else
        P=((BESSK1(ARG2)*BESSI0(ARG1)+BESSI1(ARG2)*BESSK0(ARG1))/
       S/ARG1/(BESSI1(ARG2)*BESSK1(ARG1)-BESSK1(ARG2)*BESSI1(ARG1)))
       +SK/S;


//
     P=(1422.*(TAV+460.)/PERM/H)*P;
//
     TOP=P;
     BOT=1+24.*CWS*S*S*P;
   PU=QTP*(TOP/BOT);
//
return PU;


}
//    ************************************************************
void QCPAV (double &QGC, double &QTP, double &PCMAX, double &PCAVN, double &CG,
                 double &ETA, int &IFR, double &DPSPC, int N, double V[], double SK,
                 double RW, double RE, double PERM, double PHI, double H, double VISG,
                 double TAV, double PCAVO, double SGG, int MCODE, double WM, double
TID,
```

```
                              double EPSD, double TP, double GLR, double SGL, double FL, double VPAV,
                              double BL, double PP, double PTMIN, double P1H, double AT, double AA,
                              double D, double PSPIN, double PRE[], double PSP[], int NPRES){
//

   int ICO, ICN, I;
   double DIF,PSPC,TPAD,FREG, PI;
   double PCAVO2, PCAVO22;

   PI=4.*atan(1.);
   I=0;
   ICO=0;
   ICN=0;
   PCAVO2=0.;

start:

    PSPC=FLAGR (PRE,PSP,PCAVO,1,NPRES,IERR);
    DPSPC=PSPIN-PSPC;
    PROP (CG,VISG,TAV,PCAVO,SGG,MCODE);
//   ************************************************************
//   *COMPUTE ETA AND DIMENSIONLESS PRODUCING TIME BASED ON          *
//  *THE DRAINAGE AREA.
               *
//  *CHECK FOR FLOW REGIMES (IFR=0; INFINITE ACTING,                  *
//  *IFR=1; BOUNDARY DOMINATED)
               *
//   ************************************************************
    ETA=0.0002637*PERM/PHI/(CG)/VISG;
    TPAD=ETA*TPCP/PI/RE/RE;
    IFR=0;
    FREG=TPAD-0.1;
    if(FREG >=0.)
     IFR=1;

//
    CPROD (QGC,QTP,N,V,TP,SK,RW,RE,ETA,IFR);
    QGC=DPSPC*PERM*H*QGC/24./1422./(TAV+460.);
```

```
QTP=DPSPC*PERM*H*QTP/1422./(TAV+460.);

//
PCAVSUB (PCAVN,PCMAX,TAV,PCAVO,SGG,MCODE,WM,TID,EPSD,QGC,GLR,SGL,

     FL,VPAV,BL,PP,PTMIN,P1H,AT,AA,D);

DIF=PCAVN-PCAVO;

if(fabs(DIF) > 0.1){
if(I == 0){
 PCAVO2=PCAVO;
      if(DIF > 0.)
  PCAVO=PCAVO+0.17;
      else
  PCAVO=PCAVO-0.13;
 I=1;
      goto start;
}
else{
 if(DIF > 0.)
  ICN=1;
 else
       ICN=-1;

 if((ICO/ICN) < 0){
  PCAVO22=PCAVO;
       PCAVO=(PCAVO+PCAVO2)/2.;
       PCAVO2=PCAVO22;
      }
      else{
       PCAVO2=PCAVO;
  if(DIF > 0.)
   PCAVO=PCAVO+0.17;
  else
   PCAVO=PCAVO-0.13;
      }
```

```
        }
         ICO=ICN;
                  goto start;
        }
//
        PCMAX=PCAVN*(2*(AA+AT))/(2*AA+AT);
//
        return;
                              }
//    ************************************************************
//    *                   SUBROUTINE CPROD                                  *
// *
                    *
//    *PROGRAM COMPUTES CUMULATIVE PRODUCTION FOR A GIVEN PRODUCING*
//    *TIME AND CONSTANT PRODUCTION PRESSURE USING THE LAPLACE          *
//    *DOMAIN SOLUTION AND NUMERICAL INVERSION
*
//    ************************************************************
void CPROD(double &QGC, double &QG, int N, double V[], double T, double SK, double RW,
                  double RE, double ETA, int IFR) {
//
   double A, ARG;
   double DLOGTW=.6931471805599453;
//
   QGC=0;
     QG=0;
   A=DLOGTW/T;
     for (int I=0; I < N; ++I){
                  ARG=A*(I+1);
       QGC=QGC+V[I+1]*Q(ARG, RE, RW, SK, ETA, IFR);
       QG=QG+V[I+1]*ARG*Q(ARG, RE, RW, SK, ETA, IFR);
     }

     QGC=A*QGC;
       QG=A*QG;
     if(fabs(QGC)<=pow(10,-38))
                   QGC=0.;
```

```
      if(fabs(QG)<= pow(10,-38))
                QG=0.;

//

}
//    ************************************************************
      double Q(double S, double RE, double RW, double SK, double ETA, int IFR){
//
      double P, ARG1, ARG2, Q;
    ARG1=sqrt(S/ETA)*RW;
    ARG2=sqrt(S/ETA)*RE;
//
      if(IFR == 0)
     P=BESSK0(ARG1)/S/ARG1/BESSK1(ARG1)+SK/S;
      else
       P=((BESSK1(ARG2)*BESSI0(ARG1)+BESSI1(ARG2)*BESSK0(ARG1))/
      S/ARG1/(BESSI1(ARG2)*BESSK1(ARG1)-BESSK1(ARG2)*BESSI1(ARG1)))
      +SK/S;

     Q=(1/S/S/S)/P;
//
return Q;
      }
//    ************************************************************
      void PROP(double &CG, double &VISG, double TAV, double P, double SGG, int MCODE){
//
      double DZ, P1, Z1, Z;

      PI=4*atan(1);


    VISG=GASVIS (TAV,SGG,P,IERR);

    Z=ZFAC (TAV,P,SGG,MCODE,IERR);
      P1=P*0.9;
```

```
   Z1=ZFAC (TAV,P1,SGG,MCODE,IERR);
     DZ=(Z-Z1)/(P-P1);

     CG=(1./P)-(DZ/Z);

//

     }
//   ************************************************************
void PCAVSUB(double &PCAVN, double &PCMAX, double TAV, double PCAVO, double SGG,
                      int MCODE, double WM, double TID, double EPSD, double QGC, double
GLR,
                      double SGL, double FL, double VPAV, double BL, double PP,
                      double PTMIN, double P1H, double AT, double AA, double D){

//

     double Z, RHOG, VISG, REG, FG, XLMAX, XL, P1F, RK, PL;


     PI=4.*atan(1.);

//

   Z=ZFAC(TAV,PCAVO,SGG,MCODE,IERR);
   RHOG=PCAVO*WM/Z/10.732/(TAV+460.);

   VISG=GASVIS(TAV,SGG,PCAVO,IERR);
     REG=3.527*RHOG*VPAV*TID/VISG;

     FG=FC(REG,EPSD);

     XLMAX=PI*TID*TID*D/4./144./5.615;
     XL=QGC*1000./GLR;
     if (XL > XLMAX)
             XL=XLMAX;

     P1F=0.433*SGL*FL*VPAV*VPAV*BL/772.8/TID;

     RK=RHOG*FG*VPAV*VPAV/TID/772.8/PCAVO;
     PL=PP+PTMIN+(P1H+P1F)*XL+14.7;
```

```
      PCAVN=(1.+AT/2./AA)*PL*(1.+D*RK);

      PCMAX=PCAVN*(2.*(AA+AT)/(2.*AA+AT));

//

      }
//    ***********************************************************
//
      double BESSK1(double X){
//
//    This program calculates K1(x). The program is taken from Numerical
//    Recipies by Press et al.
//
//    Subprograms Called:
//         BESSI1
//
      double BESSK1, Y;
      double P1, P2, P3, P4, P5, P6, P7;
      double Q1, Q2, Q3, Q4, Q5, Q6, Q7;

      P1=1.;
      P2=0.15443144;
      P3=-0.67278579;
      P4=-0.18156897;
      P5=-0.01919402;
      P6=-0.00110404;
      P7=-0.00004686;
//
      Q1=1.25331414;
      Q2=0.23498619;
      Q3=-0.03655620;
      Q4=0.01504268;
      Q5=-0.00780353;
      Q6=0.00325614;
      Q7=-0.00068245;
//
      if (X <= 0.){
```

```
        //cout<<"BAD ARGUMENT IN BESSK1"<<endl;
        BESSK1=0.;
        return BESSK1;
       }
//
       if (X <= 2.){
        Y=X*X/4.;
        BESSK1=(log(X/2.)*BESSI1(X))+(1./X)*(P1+Y*(P2+
               Y*(P3+Y*(P4+Y*(P5+Y*(P6+Y*P7))))));}
       else{
        Y=2./X;
        BESSK1=(exp(-X)/sqrt(X))*(Q1+Y*(Q2+Y*(Q3+
               Y*(Q4+Y*(Q5+Y*(Q6+Y*Q7))))));}
//
       return BESSK1;
       }
//     ************************************************************
double BESSI1(double X){
//     ************************************************************
//  *This program calculates I1(x). The program is taken from    *
//  *Numerical Recipies by Press et al.                          *
//     ************************************************************
       double BESSI1, Y, AX;
       double P1, P2, P3, P4, P5, P6, P7;
       double Q1, Q2, Q3, Q4, Q5, Q6, Q7,Q8,Q9;

       P1=0.5;
       P2=0.87890594;
       P3=0.51498869;
       P4=0.15084934;
       P5=0.02658733;
       P6=0.00301532;
       P7=0.00032411;
//
       Q1=0.39894228;
       Q2=-0.03988024;
       Q3=-0.00362018;
```

```
    Q4=0.00163801;
   Q5=-0.01031555;
    Q6=0.02282967;
    Q7=-0.02895312;
    Q8=0.01787654;
    Q9=-0.00420059;
//
   if (fabs(X) <= 3.75){
      Y=pow(X/3.75,2);
      BESSI1=X*(P1+Y*(P2+Y*(P3+Y*(P4+Y*(P5+Y*(P6+Y*P7))))));}
    else{
      AX=fabs(X);
      Y=3.75/AX;
      BESSI1=(exp(AX)/sqrt(AX))*(Q1+Y*(Q2+Y*(Q3+Y*(Q4+
               Y*(Q5+Y*(Q6+Y*(Q7+Y*(Q8+Y*Q9))))))));}
//
    return BESSI1;
}
//    ************************************************************
    double BESSK0(double X){
//    ************************************************************
// *This  program calculates K0(x). The program is taken from    *
// *Numerical Recipies by Press et al.                                          *
//    *
                                        *
// *Subprograms Called: BESSI0
     *
//    ************************************************************
    double BESSK0, Y;
    double P1, P2, P3, P4, P5, P6, P7;
    double Q1, Q2, Q3, Q4, Q5, Q6, Q7;


    P1=-0.57721566;
    P2=0.42278420;
    P3=0.23069756;
    P4=0.03488590;
    P5=0.00262698;
```

```
      P6=0.00010750;
      P7=0.0000074;

      Q1=1.25331414;
      Q2=-0.07832358;
      Q3=0.02189568;
      Q4=-0.01062446;
      Q5=0.00587872;
      Q6=-0.00251540;
      Q7=0.00053208;
//
      if(X <=0.){
            //cout<<"BAD ARGUMENT IN BESSK0"<<endl;
            BESSK0=0.;
            return BESSK0;
      }
//
      if (X <=2.){
            Y=X*X/4.;
            BESSK0=(-log(X/2.)*BESSI0(X))+(P1+Y*(P2+Y*(P3+
                  Y*(P4+Y*(P5+Y*(P6+Y*P7))))));}
      else{
            Y=(2./X);
            BESSK0=(exp(-X)/sqrt(X))*(Q1+Y*(Q2+Y*(Q3+
            Y*(Q4+Y*(Q5+Y*(Q6+Y*Q7))))));}
//
      return BESSK0;
}

//
//    ************************************************************
      double BESSI0(double X){
//    ************************************************************
// *This program calculates I0(x). The program is taken from    *
// *Numerical Recipies by Press et al.                          *
//    ************************************************************
      double BESSI0, Y, AX;
```

```
double P1, P2, P3, P4, P5, P6, P7;
double Q1, Q2, Q3, Q4, Q5, Q6, Q7, Q8, Q9;


P1=1;
P2=3.5156229;
P3=3.0899424;
P4=1.2067492;
P5=0.2659732;
P6=0.0360768;
P7=0.0045813;

Q1=0.39894228;
Q2=0.01328592;
Q3=0.00225319;
Q4=-0.00157565;
Q5=0.00916281;
Q6=-0.02057706;
Q7=0.02635537;
Q8=-0.01647633;
Q9=0.00392377;

if (fabs(X) < 3.75){
        Y=pow(X/3.75,2);
        BESSI0=P1+Y*(P2+Y*(P3+Y*(P4+Y*(P5+Y*(P6+Y*P7)))));}
else{
        AX=fabs(X);
        Y=3.75/AX,
        BESSI0=(exp(AX)/sqrt(AX))*(Q1+Y*(Q2+Y*(Q3+Y*(Q4
        +Y*(Q5+Y*(Q6+Y*(Q7+Y*(Q8+Y*Q9))))))));}
//
    return BESSI0;
}

//    ************************************************************
void STEHFESTV(double VV[], int NN){
```

```
double G[52],H[26];
double FI, SN;
   int NH, K, kc1, K1, K2, i, ic1;

   VV[0]=0.;
   H[0]=0.;
   G[0]=0.;
G[1]=1.;
NH=NN/2;
   for (i=0; i<NN-1; ++i){
               ic1=i+2;
               G[ic1]=G[ic1-1]*(ic1);
   }

H[1]=2.0/G[NH-1];

   for (i=0; i<NH-1; ++i){
              ic1=i+2;
   FI=ic1;
   if(ic1==NH)
                         H[ic1]=pow(FI,NH)*G[2*ic1]/(G[ic1]*G[ic1-1]);
              else
   H[ic1]=pow(FI,NH)*G[2*ic1]/(G[NH-ic1]*G[ic1]*G[ic1-1]);
   }

SN=2*(NH-NH/2*2)-1;

   for (i=0; i<NN; ++i){
              ic1=i+1;
              VV[ic1]=0.0;
   K1=(ic1+1)/2;
   K2=ic1;
   if(K2 > NH)
                         K2 = NH;

   for(K=0; K < K2-K1+1; ++K){
                 kc1=K+K1;
```

```
                    if((2*kc1-ic1)==0)
                              VV[ic1]=VV[ic1]+H[kc1]/G[ic1-kc1];
          else if (ic1==kc1)
                              VV[ic1]=VV[ic1]+H[kc1]/G[2*kc1-ic1];
                    else
                              VV[ic1]=VV[ic1]+H[kc1]/(G[ic1-kc1]*G[2*kc1-ic1]);
               }

        VV[ic1]=SN*VV[ic1];
               SN=-SN;
        }
      }
// ************************************************************
double FC(double RE, double ED){
//
     double FCI, arg, DEN, FF, DIFF, FC;
//
     if(RE < 2300.)
          FC=16./RE;
     else{
//   ************************************************************
// *CALCULATE MOODY FRICTION FACTOR WITH JAIN EQUATION FOR FIRST*
//   *GUESS FROM COLEBROOK EQUATION
               *
//   ************************************************************
          arg=1.14-2.*log10(ED+21.25/pow(RE, 0.9));
          FCI=1.0/arg/arg;
//   ************************************************************
// *SET COUNTER. COLEBROOK EQUATION IS ITERATIVE. IF CONVERGENCE*
// *IS NOT ATTAINED IN 10 ITERATIONS AN INFINITE LOOP WILL        *
//   *PROBABLY OCCUR. SET FRICTION FACTOR EQUAL TO THE VALUE          *
//   *DETERMINED IN THE 10TH ITERATION AND USE WITH CAUTION           *
//   ************************************************************
          DIFF=1.0;
          int i=0;
          do {
               i=i+1;
```

```
                DEN=1.14-2.0*log10(ED+9.34/(RE*sqrt(FCI)));
                FF=pow(1.0/DEN, 2);
                DIFF=fabs(FCI-FF);
                FCI=(FCI+FF)/2.0;
            } while(DIFF > 0.00001 && i < 10);

            FF=FCI;

            FC=FF/4.0;
        }
return FC;
}
//    ***************************************************************
//
//    This subroutine calculates viscosity of hydrocarbon gases from
//    the following correlation.  The English system of units is used
//    in the calculation.
//
//    - Viscosity of hydrocarbon gases calculation:
//      The Lee et al correlation is used.
//
//
//                         REFERENCES
//                         ----------
//
//    1.  Brill, J. P. and Beggs, H. D.:  Two-Phase Flow in Pipes
//            (Feb. 1984) 2-58 thru. 2-63.
//    2.  Lee, A. L., et al.:  "The Viscosity of Natural Gases,"
//            Transactions, AIME (Aug. 1966) 997-1000.
//
//    *************************************************************
//
//                      SUBPROGRAM CALLED
//                      ----------------
//
//    ZFAC = This subroutine calculates gas compressibility factor.
//
```

```
//
//                    VARIABLE DESCRIPTION
//                    --------------------
//
//     DENSI = Gas density. (gm/cc)
//     IERR  = Error code. (0=OK, 1=input variables out of range,
//             2=extrapolation of correlation occuring)
//     IOERR = Output file for error messages when input values
//             passed to the subroutine are out of range.
//    *P     = Pressure. (psia)
//    *SGFG  = Specific gravity of free gas.
//    *T     = Temperature. (deg-F)
//     TABS  = Absolute temperature. (deg-R)
//     VISG  = Gas viscosity. (cp)
//     W     = Molecular weight.
//     Z     = Real gas compressibility factor.
//
//     AK,X,Y = Dummy variables.
//     (* Indicates input variables)
//
//    *****************************************************************
    double GASVIS (double T, double SGFG,double P, int IERR){


    double TABS, AK, W, XX, YY, ZFACTOR, DENSI, GASVIS;
    int MCODE;

//    *************************************
//    Check input variables for valid range.
//    *************************************

    IERR=0;
     if (T < 0.0 || T > 400.0){
     //cout<<"GASVIS:  Illegal input value for T"<<endl;
     IERR=1;}
     if (SGFG < 0.20 || SGFG > 1.7){
     //cout<<"GASVIS:  Illegal input value for SGFG"<<endl;
```

```
                IERR=1;}
        if(P < 0.0){
                //cout<<"GASVIS:  Illegal input value for P"<<endl;
                IERR=1;}
        if(IERR==1){
                GASVIS = 0.;
                return GASVIS;}
//
//    -------------------------------------------------
//    Check input variables for valid correlation range.
//    -------------------------------------------------
//
    //  if (T < 100.0 || T > 340.0)
    //          cout<<"T is out of range for the Lee correlation in GASVIS\n"<<
    //                      "and extrapolation is occuring\n"<<endl;
  // else
            //if (P < 100.0 || P > 8000.0)
            //cout<<"P is out of range for the Lee correlation in GASVIS\n"<<
            //          "and extrapolation is occuring\n"<<endl;
//
//    **********************
//    End of validity check.
//    **********************
//
            TABS=T+460.;
            W=SGFG*29.;
            AK=(9.4+.02*W)*(pow(TABS,1.5))/(209.+19.*W+TABS);
            XX=3.5+(986./TABS)+.01*W;
            YY=2.4-.2*XX;
//
//    ---------------------
//    Calculate gas density.
//    ---------------------
//
            MCODE=0;
      ZFACTOR=ZFAC(T,P,SGFG,MCODE,IERR);
      DENSI=P*W/(10.72*ZFACTOR*TABS*62.4);
```

```
//
//    ------------------------
//    Calculate gas viscosity.
//    ------------------------
//
      VISG=AK*exp(XX*pow(DENSI,YY))/10000;
//
      GASVIS=VISG;
//
      return GASVIS;
      }
//
//    ****************************************************************
//
//    This subroutine calculates gas compressibility factor from the
//    following correlations.  The English system of units is used in
//    the calculation.
//
//    - Gas compressibility factor correlations used are selected by
//      MCODE to be either:
//         0:  The Hall and Yarborough correlation for curve fitting
//             the Standing-Katz reduced pressure-reduced temperature
//             Z-Factor chart.
//         1:  The standing modification to the Brill and Beggs
//             correlation for curve-fitting the Standing-Katz reduced
//             pressure-reduced temperature Z-Factor chart.
//         2:  The Dranchuk, Purvis and Robinson correlation for curve
//             fitting the Standing-Katz reduced pressure-reduced tem-
//             perature Z-Factor chart.
//      or 3:  The Gopal correlation for curve fitting the Standing-
//             -Katz reduced pressure-reduced temperature Z-Factor
//             chart.
//
//
//                        REFERENCES
//                        ----------
//
```

```
//    1.  Brill, J. P. and Beggs, H. D.:  Two-Phase Flow in Pipes
//          (Feb. 1984) 2-33 thru. 2-47.
//    2.  Dranchuk, P. M., Purvis, R. A. and Robinson, D. B.:  "Computer
//          Calculation of Natural Gas Compressibility Factors Using
//          the Standing and Katz Correlation," Institute of Petroleum
//          Technical Series, NO. IP74-008, 1974.
//    3.  Gopal, V. N.:  "Gas Z-Factor Equations Developed for Computer,"
//          Oil and Gas Journal (Aug. 8, 1977) 58-60.
//    4.  Hall, K. R. and Yarborough. L.:  "A New Equation of State for
//          Z-Factor Calculations,"  Oil and Gas Journal (June 18,
//          1973) 82-92.
//    5.  Standing, M. B.:  " Volumetric and Phase Behavior of Oil Field
//          Hydrocarbon Systems", Society of Petroleum Engineers
//          (8th Printing, 1977) 121-127.
//    6.  Standing, M. B. and Katz, D. L.:  "Density of Natural Gases,"
//          Transactions, AIME, 196. (1942) 140-149.
//    7.  Yarborough, L. and Hall, K. R.:  "How to Solve Equation of State
//          for Z-Factors,"  Oil and Gas Journal (Feb. 18, 1974)
//          86-88.
//
//    ****************************************************************
//
//                     VARIABLE DESCRIPTION
//                     --------------------
//
//     DENR  = Reduced density.
//     IERR  = Error code. (0=OK, 1=input variables out of range,
//          2=extrapolation of correlation occuring)
//    MCODE = Z-Factor correlation selection parameter:
//             0 = Hall and Yarborough
//             1 = Standing
//             2 = Dranchuk, Purvis and Robinson
//             3 = Gopal.
//    *P     = Pressure. (psia)
//     PC    = Critical pressure. (psia)
//     PR    = Reduced pressure.
//     RT    = Inverse of reduced temperature.
```

```
//    *SGFG  = Specific gravity of free gas.
//    *T     = Temperature. (deg-F)
//     TC    = Critical temperature. (deg-R)
//     TR    = Reduced temperature.
//     Y     = Data for equation coefficients.
//     Z     = Real gas compressibility factor.
//
//    A,B,//,D,E,F,G,DFDY,FN,I,J,K = Dummy variables.
//     (* Indicates input variables)
//
//    *************************************************************
//
double ZFAC (double T, double P, double SGFG, int MCODE, int IERR){


         double TC, PC, TR, PR, ZFAC;

//    ************************************
//    Check input variables for valid range.
//    ************************************
         IERR=0;
         TC=0.;

         if (T < 0. || T > 800.){
                   //cout<<"ZFAC:  Illegal input value for T in ZFAC"<<endl;
         IERR=1;
         }
         if(P < 0. || P > 10000.){
                   //cout<<"ZFAC:  Illegal input value for P in ZFAC"<<endl;
                   IERR=1;
         }
         if(SGFG < 0.55 || SGFG > 1.5){
                   //cout<<"ZFAC:  Illegal input value for SGFG in ZFAC"<<endl;
                   IERR=1;
         }
         if(MCODE < 0 || MCODE > 3){
                   //cout<<"ZFAC:  Illegal input value for MCODE in ZFAC"<<endl;
```

```
                IERR=1;
        }
//      *********************
//      End of validity check.
//      *********************

        if(IERR == 1)
                ZFAC = 0.;
        else{
//
//      -----------------------------------------------------
//      Calculate critical and reduced temperature and pressure.
//      -----------------------------------------------------

        TC=169.0+314.0*SGFG;
        PC=708.75-57.5*SGFG;
        TR=(T+460.0)/TC;
        PR=P/PC;
//
//      ---------------------------
//      Select Z-Factor correlation.
//      ---------------------------
//
                if (MCODE == 0)
          hallyarbcorr (ZFAC, PR, TR);
                else if (MCODE == 1)
                        standingcorr (ZFAC, PR, TR);
        else if (MCODE == 2)
          dranchukcorr (ZFAC, PR, TR);
                else
                        gopalcorr (ZFAC, PR, TR);
        }
//
        return ZFAC;
}
//
//      ******************************
```

```
//    HALL AND YARBOROUGH CORRELATION
//    ******************************
//
//    ------------------------------------------------------------

      void hallyarbcorr (double& Z, double PR, double TR){

//    If reduced temperature is less than 1.01, calculate a Z-Factor
//    for a reduced temperature value of 1.0.
//    ------------------------------------------------------------
        double RT, A, B, C, D, F, DENR, DFDY;

              if (TR > 1.01)
                     RT=1./TR;
              else
                     RT=1.;
//    -------------------------------------
//    Calculate temperature dependent terms.
//    -------------------------------------
//
       A=0.06125*RT*exp(-1.2*pow(1.-RT,2));
       B=RT*(14.76-9.76*RT+4.58*RT*RT);
       C=RT*(90.7-242.2*RT+42.4*RT*RT);
       D=2.18+2.82*RT;

//    ---------------------------------------------------------------
//    Calculate reduced density, DENR, using the Newton-Raphson method.
//    ---------------------------------------------------------------

              DENR=.001;

              for(int j=0; j < 25; ++j){
                     if (DENR > 1)
                            DENR=.6;

                     if( DENR <= 0){
                      gopalcorr(Z, PR, TR);
```

```
                        return;
                }
                F=-A*PR+(DENR+DENR*DENR+pow(DENR,3)-pow(DENR,4))/pow(1.-
DENR,3)
                        -B*DENR*DENR+C*pow(DENR,D);

                if(fabs(F)<=.0001){
//      ------------------
//      Calculate Z-factor.
//      ------------------

                        Z=A*PR/DENR;
                        return;
                }
//      ----------------------------------------------------------
//      If convergence is not obtained in 25 iterations, set Z=1.0
//      and return.
//      ----------------------------------------------------------

                if (j < 24){
                        DFDY=(1.+4.*DENR+4.*DENR*DENR-
4.*pow(DENR,3)+pow(DENR,4))
                                /pow((1.-DENR),4)-2.*B*DENR+D*C*pow(DENR,(D-1.));
                        DENR=DENR-F/DFDY;}
                else{
                        Z=1;
                        return;}
            }
    return;
        }

//      *******************
//      STANDING CORRELATION
//      *******************
        void standingcorr (double& Z, double PR, double TR){

                double A, B, C, D, E, F, G;
```

```
        if (TR < 1.2 || TR > 2.4) {
                gopalcorr(Z, PR, TR);
                return;
        }
    A=1.39*pow(TR-.92,0.5)-.36*TR-.101;
    B=(.62-.23*TR)*PR;
    C=(.066/(TR-.86)-.037)*pow(PR,2);
    D=(.32/(pow(10,(9.*(TR-1.)))))*pow(PR,6);
    E=B+C+D;
    F=(.132-.32*log10(TR));
    G=pow(10,(.3106-.49*TR+.1824*pow(TR,2)));
//
//   -------------------
//   Calculate Z-Factor.
//   -------------------
//
    Z=A+(1.-A)*exp(-E)+F*pow(PR,G);
    return;
   }

//   ****************************************
//   DRANCHUK, PURVIS AND ROBINSON CORRELATION
//   ****************************************

   void dranchukcorr(double& Z, double PR, double TR)
   {
//
   double A, B, C, D, E, F, G, DENR, DFDY, FN;
//   ------------------------------------------------------------
//   Calculate Benedict-Webb-Rubin Equation of State Coefficients.
//   ------------------------------------------------------------
//
    A=0.06423;
    B=0.5353*TR-0.6123;
    C=0.3151*TR-1.0467-0.5783/pow(TR,2);
    D=TR;
    E=0.6816/pow(TR,2);
```

```
        F=0.6845;
        G=0.27*PR;
//
//  ------------------------------------------------------------
//  Guess initial value for reduced density and use the Newton-
//  Raphson iteration method to determine reduced density.
//  ------------------------------------------------------------
//
              DENR=0.27*PR/TR;
              for(int i=0; i<25; ++i){

    FN=A*pow(DENR,6)+B*pow(DENR,3)+C*pow(DENR,2)+D*DENR+E*pow(DENR,3)
                      *(1.0+F*pow(DENR,2))*exp(-F*pow(DENR,2))-G;

                   if (fabs(FN) <= 0.0001){

//  -------------------
//  Calculate Z-Factor.
//  -------------------
//
            Z=0.27*PR/(DENR*TR);
            return;
                   }

//  ------------------------------------------------------------
//  If convergence is not obtained in 25 iterations, set Z=1.0
//  and return.
//  ------------------------------------------------------------
//
                   if (i < 24) {

DFDY=6.0*A*pow(DENR,5)+3.0*B*pow(DENR,2)+2.0*C*DENR+D+E*pow(DENR,2)
           *(3.0+F*pow(DENR,2))*(3.0-2.0*F*pow(DENR,2))*exp(-F*pow(DENR,2));
                        DENR=DENR-FN/DFDY;}
                   else{
                        Z=1.;
                        return;}
              }
```

```
        return;
    }
//
//  *****************
//  GOPAL CORRELATION
//  *****************
//
void gopalcorr(double& Z, double PR, double TR)
{

    double Y[49];
    int i, j, k;

     Y[0]=0;
     Y[1]=1.6643;
     Y[2]=-2.2114;
     Y[3]=-.3647;
     Y[4]=1.4385;
     Y[5]=.5222;
     Y[6]=-.8511;
     Y[7]=-.0364;
     Y[8]=1.0490;
     Y[9]=.1391;
     Y[10]=-.2988;
     Y[11]=.0007;
     Y[12]=.9969;
     Y[13]=.0295;
     Y[14]=-.0825;
     Y[15]=.0009;
     Y[16]=.9967;
     Y[17]=-1.3570;
     Y[18]=1.4942;
     Y[19]=4.6315;
     Y[20]=-4.7009;
     Y[21]=.1717;
     Y[22]=-.3232;
     Y[23]=.5869;
```

```
Y[24]=.1229;
Y[25]=.0984;
Y[26]=-.2053;
Y[27]=.0621;
Y[28]=.8580;
Y[29]=.0211;
Y[30]=-.0527;
Y[31]=.0127;
Y[32]=.9549;
Y[33]=-.3278;
Y[34]=.4752;
Y[35]=1.8223;
Y[36]=-1.9036;
Y[37]=-.2521;
Y[38]=.3871;
Y[39]=1.6087;
Y[40]=-1.6635;
Y[41]=-.0284;
Y[42]=.0625;
Y[43]=.4714;
Y[44]=-.0011;
Y[45]=.0041;
Y[46]=.0039;
Y[47]=.0607;
Y[48]=.7927;

if (PR < 0.199)
 Z=1.;
else {
        if (PR > 5.4)
  Z=PR*pow(.711+3.66*TR,-1.4667)-1.637/(.319*TR+.522)+2.071;
        else {
                i=1;
                if (PR > 1.2){
                        if(PR > 1.4 || TR < 1.08 || TR > 1.19) {
                                if (PR <= 2.8)
         i=2;
```

```
            else
              i=3;

                            }
                      }
                      k=4;
      if (TR <= 2.0)
                            k=3;
      if (TR <= 1.4)
                            k=2;
      if (TR <= 1.2)
                            k=1;
      if (TR <= 1.0){
                            Z=1.;
                            return;
                      }
                      j= 16*i+4*k-19;

                      Z=PR*(Y[j]*TR+Y[j+1])+Y[j+2]*TR+Y[j+3];
              }
      }
return;
}

//   ****************************************************************
//
//   This subroutine uses the Lagrange Formula to evaluate the
//   interpolating polynomial of degree IDEG for argument XARG using
//   the data values X(MIN).....X(MAX) and Y(MIN).....Y(MAX) where
//   MIN = MAX-IDEG. The X(I) values are not necessarily evenly
//   spaced and can be in either increasing or decreasing order.
//
//   Interpolation routine similar to      in 'Applied Numerical
//   Methods' by Carnahan, Luther and Wilkes.
//
//
//                          REFERENCE
```

```
//                    ---------
//
//  1. Carnahan, Luther and Wilkes.:  Applied Numerical Methods,
//       John Wiley and Sons (1969) 29-34.
//
//  ************************************************************
//
//                  VARIABLE DESCRIPTION
//                  --------------------
//
//  *IDEG  = Degree of interpolating polynomial (1 is linear, 2 is
//       quadratic, etc).
//   IERR  = Error code. (0=OK, 1=input variables out of range)
//  *NPTS  = The number of data points in x and y.
//  *X     = The array of independent variable data points.
//  *XARG  = The argument for which an interpolated value is desired.
//  *Y     = The array of dependent variable data points.
//
//   N,N1,L = Dummy variables.
//   I,J = Loop variables.
//   (* Indiates input variables)
//
//  ************************************************************
//
    double FLAGR (double X[], double Y[], double XARG, int IDEG,
                      int NPTS, int IERR){

    int MAX, NN, N1;
    double FLAGR;
//
    IERR=0;
    FLAGR=0;
    if (IDEG < 1){
            //cout<<"FLAGR:  Illegal value input for IDEG"<<endl;
            IERR=1;}

    if (NPTS < 3){
```

```
                    //cout<<"FLAGR:  Illegal value input for NPTS"<<endl;
                    IERR=1;}

    if (IERR == 1){
            FLAGR=0.;
            return FLAGR;
    }
//
//  ********************
//  End of validity check
//  ********************
//
    NN=abs(NPTS);
   N1=IDEG+1;

    if(X[2] > X[1]){
//
//  ------------------------------------------------------------
//  Check to be sure that XARG is within range of X(I) values
//  for interpolation purposes. If it is not, set FLAGR equal
//  to the appropriate terminal value (Y(1) or Y(N)) and return.
//  Note that this precludes extrapolation of data.
//  ------------------------------------------------------------

            if (XARG <= X[1]){
                    FLAGR=Y[1];
                    return FLAGR;}
    else
                    if (XARG >= X[NN]){
                      FLAGR=Y[NN];
                            return FLAGR;}
                    else
//  ------------------------------------------
//  Data are in order of increasing value of x.
//  ------------------------------------------
                            for (int i=0; i < NN-N1+1; ++i){
                                    int MAX=i+N1;
```

```
                                    if (XARG < X[MAX])
                                              FLAGR=YEST(X,Y,MAX,IDEG,XARG);}
     }
     else
               if (XARG >= X[1]){
        FLAGR=Y[1];
                         return FLAGR;}
      else
                         if (XARG <= X[NN]){
          FLAGR=Y[NN];
                           return FLAGR;}
                         else
//
//     -------------------------------------------
//     Date are in order of decreasing value of x.
//     -------------------------------------------
//
                              for (int i=0; i < NN-N1+1; ++i){
                                    MAX=i+N1;
                                    if (XARG > X[MAX])
                                              FLAGR=YEST(X,Y,MAX,IDEG,XARG);}

return FLAGR;
     }
//
     double YEST(double x[],double y[], int MAX, int IDEG, double XARG){
//
               int MIN;
               double FACTOR, TERM, YEST;

               MIN=MAX-IDEG;
               FACTOR=1.;
               for(int i=0; i < MAX-MIN+1; ++i) {
                          int ic=i+MIN;
                          if (XARG == x[ic]){
                                    YEST=y[ic];
                                    return YEST;}
```

```
                FACTOR=FACTOR*(XARG-x[ic]);
        }
        YEST=0;
        for (i=0; i <MAX-MIN+1; ++i){
                int ic=i+MIN;
                TERM=y[ic]*FACTOR/(XARG-x[ic]);

                for (int j=0; j < MAX-MIN+1; ++j){
                        int jc=j+MIN;
                        if (ic != jc)
                                TERM=TERM/(x[ic]-x[jc]);}
                YEST=YEST+TERM;
        }
return YEST;
    }



//  -----------------Opens the well --------------------------------
void open_well(float TP){
    cout<<"Opening Well for "<< TP*HRS<<" miliseconds"<<endl;
}



// ------------------Closes the well -------------------------------
void close_well(float DT){
    cout<<"Closing Well for "<< DT*HRS<<" miliseconds"<<endl;
}
```

B. Input Data String

TID,TOD,CID,D,WP,PTMIN

SGL,SGG,VPAV,TAV,GLR,VISL

EPSD

PIN,PERM,PHI,CF,CWS,SK,RW,RE,H
PMIN,PMAX,NPRES,N

C. Example Input Data File:

```
1.995 2.375 4.09 6318. 8.0 29.9
0.834 0.72 15.4 100. 6365. 0.82
0.00003
270. 12. 0.13 0.000002 0.00000047 2.5 0.25 840.34 77.
29. 270. 40 16
```

Waterflooding in Gordon Sandstone Formation – Taylorstown Field

during the Period 05/15/2001 to 11/30/2002

By

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The Energy Institute
East Resources Incorporated

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By
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The College of Earth and Mineral Science
The Department of Energy and Geo-Enviromental Engineering
The Energy Institute
East Resources Incorporated

DISCLAIMER

ABSTRACT

The Appalachian Region contains hundreds of oil fields that were developed during the late 1800's and/or early 1900's. These fields contain oil reserves that may be recovered using secondary recovery methods such as waterflooding. Technical and economic evaluation of these fields for these capital-intensive operations requires in-depth engineering studies that usually include a field-scale computer model. However, the data needed for building such models are lacking given that modern tools for formation evaluation were not available when these fields were developed (early 1900's).

The objectives of this study are to develop techniques for simulating these first-generation oil fields and to analyze the dynamic nature of near-wellbore damage of injection and production wells. These techniques are demonstrated for the Taylorstown field located in Washington County, PA. This reservoir (Upper Devonian Gordon Sandstone), which is currently undergoing waterflooding, is used as case study. Reservoir model of the field was developed and used to study the dynamic skin damage effect.

This study describes the approach, and protocol employed to characterize and build the computer model of the field in spite of the sparse data sets. The protocol utilizes a systematic approach to complete the history matching, which proved to be effective in understanding the behavior of the reservoir under study. The results obtained provide the operators of the Appalachian basin with a tool to characterize, initialize and perform computer simulation studies of any of the hundreds of reservoirs found in the basin.

It was concluded that the change in well-bore damage with time in waterflooding operations might result from the types of fluids injected. In the Washington-Taylorstown field, it appears that the major factor was a history of gas injection and water injection using water obtained from coalmine operations and gas fields. This resulted in the presence of mobile emulsions and suspended solids that reduced injectivity and productivity of injection and production wells, respectively.

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1.0 INTRODUCTION

The goal of reservoir engineering and its attendant studies is to maximize oil recovery from the subject reservoir. During the primary production phase, it is the management of the natural energy of the reservoir that maximizes the production. However, continued production at an economic level typically requires implementation of secondary recovery technologies such as waterflooding.

With waterflooding, collateral effects come into the picture since the reservoir is being perturbed. This study presents guideline for the development of reservoir models where “insufficient” data are available and concentrates on the effects of water injection on the rock matrix, specifically skin damage. Skin damage can be caused by a variety of external or internal mechanisms. These mechanisms can include damage that result from fluid invasion during the drilling operation. It can also result from the impact of fluid injection and or production on the reservoir rock. Skin damage is quantified by dimensionless pressure drop that is referred to as skin factor.

The purpose of this study is to investigate the skin factor as a time dependent function, in other words, an investigation of dynamic skin. In order to achieve this objective, numerical reservoir simulation is used as the platform for the analysis of the reservoir performance. Data obtained from the reservoirs undergoing waterflooding are used to support the study.

Numerical reservoir simulation is a tool widely employed by reservoir engineers to understand the past and present behavior of a reservoir. It is also used to estimate rock and fluid properties, and for predicting future performance of a field under various operating conditions. In reservoir simulation, rock and fluid properties are characterized and used to build a mathematical model. This model is then used to solve the governing partial differential equations that describe the movement of the different phases in the reservoir, and thereby mimic the time-dependent variation of pressure and production rates.

During the construction of the model, a matching of the historical data and simulation results is used to adjust the values of the properties assigned, and verify the boundary conditions of the model. A “good” qualitative and quantitative match validates the accuracy of the model, and confirms the ability of the mathematical model to recreate the complex behavior of the reservoir. Using numerical reservoir simulation, engineers can forecast production of oil, water and gas, estimate the reserves and evaluate the viability of the project under of various operating scenarios.

1.1 Background

To accomplish the study of dynamic skin, data from ongoing field operations were used. The data were from the Gordon sandstone formation found in the Appalachian Basin. The Gordon sand belongs to the Venango group of the Upper Devonian age and received its name in 1885 when discovered by drilling operations on the Gordon farm in Washington, Pennsylvania.

Among the most predominant properties that characterize the sandstone at this location are: 1) the depth at which it is found (between 1500-ft and 3000-ft); 2) the permeability ranges (from 90-md to 200-md); and 3) the average porosity value of approximately 20 percent. Values out of these ranges could generally be found in any of the wells penetrating this formation (*Harper, 1987 and Lytle, 1950*).

The area of interest related to the study is located in Washington County, southwest Pennsylvania, where the field of Washington-Taylorstown is located. The field produces from the Gordon sand formation and is one of the many fields found in Pennsylvania, Ohio and West Virginia that have the potential for waterflooding.

Fields penetrating the Gordon formation were discovered in the late 1800s and at the beginning of the 20th century. During the early development stage of the fields, primary production was the principal mechanism for oil production. However, this primary production ended by the middle of the century because the reservoir drive mechanism was depleted. It was estimated that approximately 10 to 25 percent of the original oil in place had been recovered. Therefore, alternative recovery methods have been studied to keep these stripper well reservoirs economically profitable (*Cardwell, 1978*). Stimulation and secondary oil recovery projects were applied to different areas of the reservoir, with varying degrees of success. Gas injection and waterflooding were the most widely secondary recovery methods even though air injection has also been practiced.

It is postulated that the implementation of these secondary recovery projects has resulted in significant damage in the wellbore and the adjoining reservoir. This study seeks to use the field data to quantify the dynamics of skin damage.

1.2 Problem Statement

To simulate and analyze the behavior of a reservoir it is often necessary to develop a field scale computer model. However, data of the type necessary for building the model are often quite sparse. The lack of data is often the case with reservoirs that were developed before the availability of modern tools for formation evaluation, or when data from the early stages of the development of the fields are not available. Given this problem, this study focuses on detailing the efforts and techniques used to develop a model for reservoirs with sparse data sets. Also, this study analyzes several factors to improve the history matching process in fields with sparse data sets.

The skin factor is the representation of a damaged or stimulated wellbore. Skin damage is present from the time a well is drilled, and then completed. It is present during the entire life of the well whether the well is in operation for production or injection purposes.

Although skin effect has been the subject of numerous investigations, e.g. Fetkcovich (1973), Tippie et al. (1974), Blacker (1982) and Hansen et al. (2002), the dynamic nature of the phenomenon has not been thoroughly investigated. Dynamic skin is influenced by a variety of parameters that cause the productivity index of the well to vary. It is well understood that operating conditions are not always the same. For example, the reservoir conditions may change with oil production and fluid injection rates may vary with well stimulation and/or mobilization of suspended particles by the injected fluid. These changes and their impact on the wellbore (skin damage) must be considered in conducting a reservoir analysis.

Analysis of the impact of dynamic skin on production and injection rates is the focus of this investigation. To achieve these objectives, the Washington-Taylorstown field is used as the case study. The results of these analyses are used to provide insight concerning the dynamic skin.

The representation of the dynamic skin effect is made with numerical reservoir simulation. A commercial black oil model simulator (Eclipse 100) is used as the tool to pursue the principal objective of this study. The methodology used to develop the model is the history matching process, which when coupled with current field operating reports confirm the veracity of this approach.

2.0 CHARACTERIZATION OF THE RESERVOIR

The Gordon sandstone formation is located in the Appalachian Basin. This formation is of Venango group in the Upper Devonian age. Primary production from these fields occurred during the late 1800's and early 1900's. With depletion, remaining oil recovery will require implementation of a secondary recovery method such as waterflooding.

The case study presented in this research is the Washington-Taylorstown field located in Pennsylvania. This field is of the Gordon sandstone formation. Specific characteristics of the Gordon sandstone at Washington-Taylorstown are not available. Given this lack of data concerning reservoir properties, average values are generally used. These "rule of thumb" values are based on the few cores that have been obtained from wells penetrating the Gordon sandstone and from historical records available from the State Geological Surveys. The data include peculiarities with respect to deposition and/or saturation distribution. The fluid properties are also shown in a section of this chapter. Oil produced from both of the fields appear to be similar in terms of viscosity, API gravity and density.

2.1 Washington-Taylorstown field

This reservoir is located in southwestern Pennsylvania, specifically in Washington County, and covers an area of 4858 acres. The drilling for oil and gas in this area started as early as 1861, but it was not until 1885 that the Washington-Taylorstown field was discovered and production began (*Harper, 1987*).

In the study area, the top of the structure is found at an average depth of 1330-ft below datum level (sea level). The depth of field trends south to north with the southern portion of the field being 70-ft deeper than the northern portion. As a consequence, the rate of change of the gravitational forces along the north-south axis of the field is 1-ft per 240-ft of length. The difference in depth between the east and the west side of the reservoir is approximately 20-ft. In terms of the gravitational effect on fluid flow, it would appear that the principal impact is felt in the north-south direction. It is also noted that the reservoir properties such as thickness and absolute permeability vary along this axis.

The well wireline logs confirmed the gross thickness and net thickness of the reservoir provided by the isopach maps. These properties average 25-ft and 9-ft respectively. Higher values of both gross thickness and net thickness are found along the main axis in the north-south direction and tend to thin out toward the edges of the reservoir. As a consequence the reservoir shape is characterized as a half pipe that runs in the north-south direction (see Figure 2.1).

The distribution of porosity in the reservoir varies slightly, with maximum values lying along the centerline of the north-south axis. The overall porosity of the field averages 20 % with maximum values of 45 % at the centerline of the reservoir and 4 % at the boundaries.

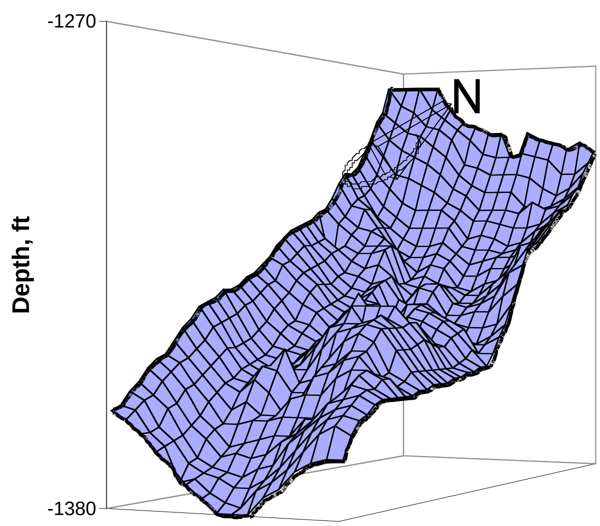


Figure 2.1: Washington-Taylorstown field, bottom of the formation.

One of the most important properties in any reservoir characterization study is the permeability. The permeability is considered as an anisotropic property. The directional distribution has the principal flow

flow trend in the northeast-southwest direction, i.e. the axis running along the injection line-drive. The axis in the northwest-southeast direction represents the secondary flow direction.

The average permeability in the northeast-southwest direction is 130 md and in the northwest-southeast direction, the average permeability is 110 md. Two regions, one on the northeastern portion and the other in the southwestern portion of the field, have permeability values as high as 250 md and 180 md, respectively (Figure 2.2). The previously referred values of directional permeability were obtained from the validation of the computer model, after the history matching process was achieved.

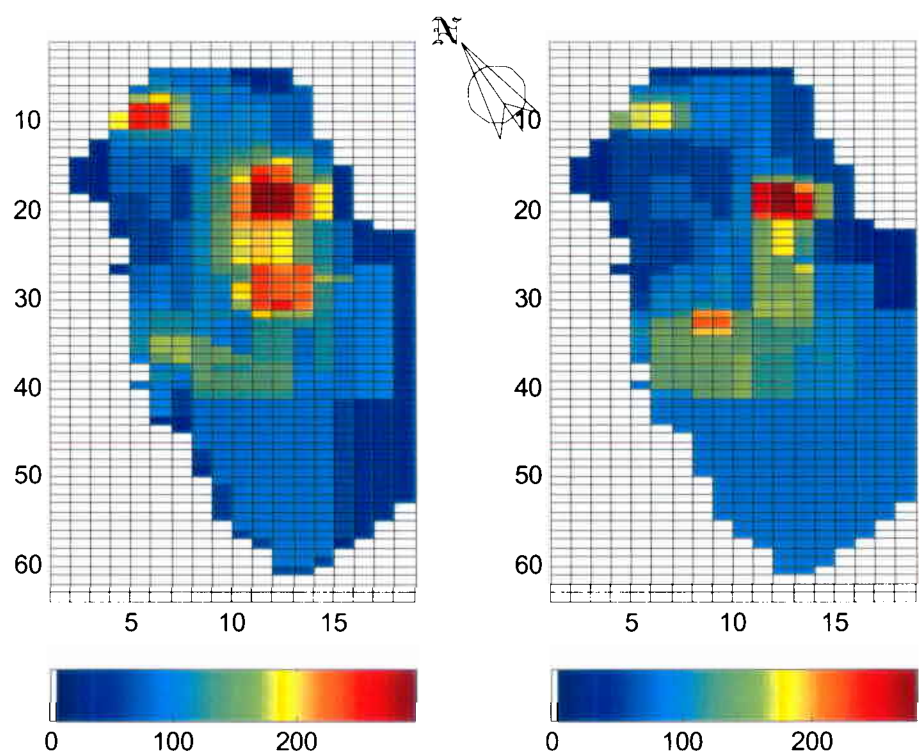


Figure 2.2: Washington-Taylorstown field isoperm maps, directional permeability in the NW-SE (left) and NE-SW (right) directions.

Other properties necessary for the reservoir analysis are saturation of the phases and their distribution. In the case of gas saturation, the operator provided a map of the unit indicating the distribution of the gas saturation. Geologist using values of gas saturation obtained from neutron logs developed the map. The map indicates that the gas saturation toward the southern portion of the reservoir is approximately 10 %. The gas saturation values increase in the center region to approximately 20 % to 30 % and to 50 % to 60 % in the northern region. The water saturation distribution was estimated from resistivity logs obtained from injection wells. From these logs, initial water saturation averages 25 %. The oil saturation considering the variation of water and gas saturations varies from 25 % in the northern area to 70 % in the south.

Using the distribution of phase saturations and reservoir properties (net pay and porosity) it was estimated that approximately 23 MMbbl of oil and 8 MMbbl of gas are contained in the reservoir. These calculations are based on conditions as of 1982.

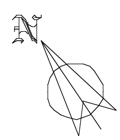
2.1.1 Washington-Taylorstown field production history

As previously mentioned, the production of the Washington-Taylorstown field started as early as 1885 with 90 barrels of oil per day well. By the end of the century, production from this field was almost 4500 BOPD. However, by 1940, 50 % of all wells to that point in time were inactive.

By today's standards these remaining wells are considered to be stripper wells and are marginally economic. Additional hydrocarbon production would require the implementation of a secondary recovery technique such as waterflooding.

At the present, the field consists of 13 active production wells located east and west of the injection line drive; 6 to the west, 6 to the east and 1 south of the injection line-drive. A map containing the locations of the wells is shown in Figure 2.3. Oil production from the unit started in 1997 with J. Hodgens Sr. 6 well. This well was the sole producer until February 1999 when the drilling of additional wells began. Drilling continued until April 2000. For the purpose of the study, production is considered to have continued until January 2002. The field has produced approximately 60 Mbbl of oil and 67 Mbbl of water during 6 years of water injection. Figure 2.4 contains a plot of cumulative production of oil and water from the field.

By the second half of 1999, the field experienced an increase in cumulative oil production. It went from 3 Mbbl during the first 2 years to approximately 7.9 Mbbl during the next 6 months. At the same time and 3.5 years after the water injection, cumulative water production increased from approximately 400 bbl to almost 8 Mbbl.



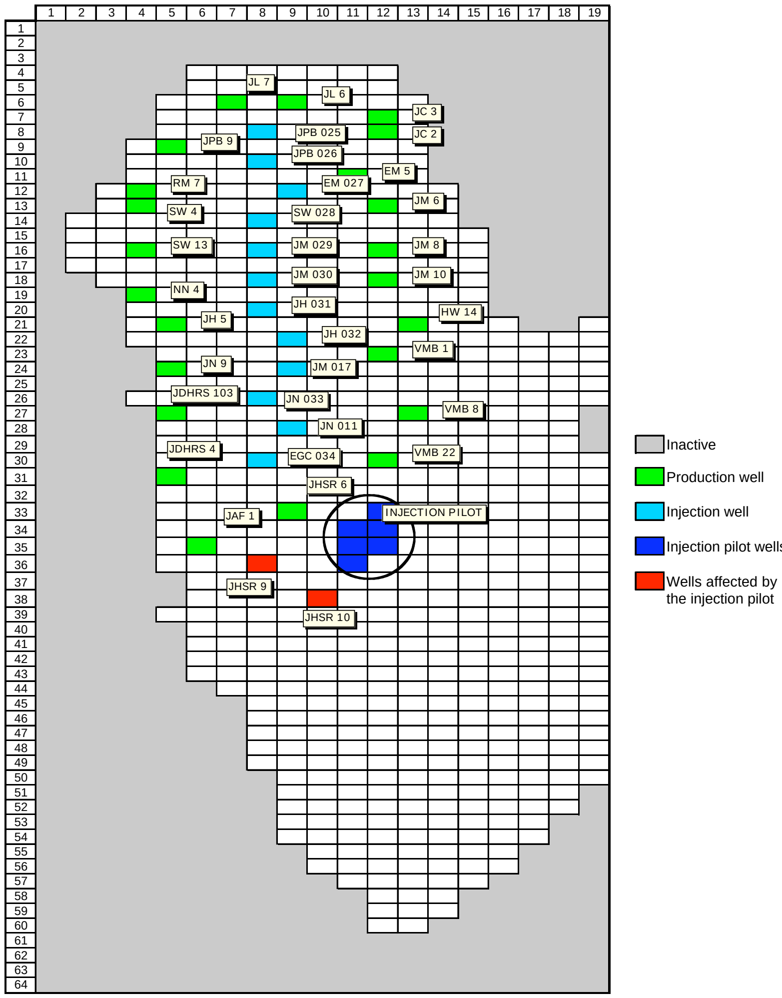


Figure 2.3: Washington-Taylorstown field, location of the active production and injection wells.

This increase in the crude and water production is believed to coincide with the arrival of the oil bank. Interestingly, the J.A. Flack 1 well, the largest cumulative oil producer in the unit, produced this oil during this six month period. At present, production is realized from 5 of the 13 production wells. These are the J.A. Flack 1, V.M Blayney 1, V.M Blayney 8, V.M Blayney 22 and J.P. Bigham 9. This field was a primary producer of oil, gas and water, but only data for the production of the liquids (oil and water) have been collected. The resulting uncertainty with respect to initial reservoir content could not be avoided and resulted in the use of estimates with respect to initial reservoir conditions.

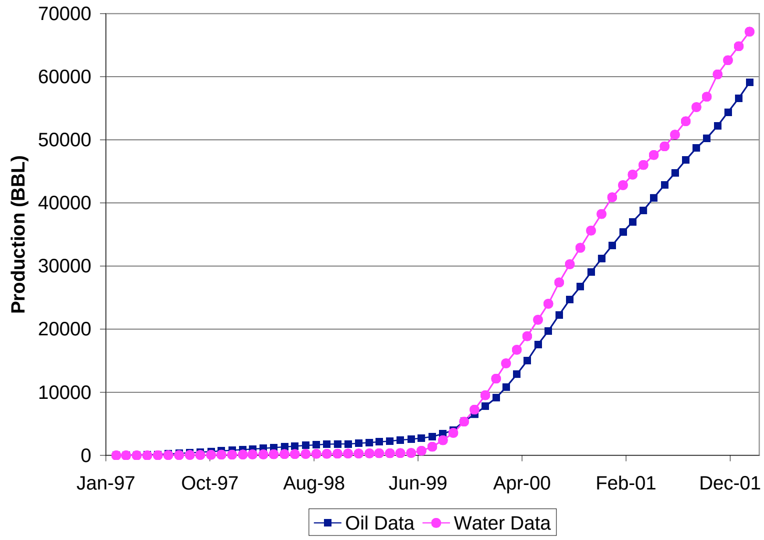


Figure 2.4: Washington-Taylorstown field, cumulative water and oil production.

2.1.2 Washington-Taylorstown field secondary recovery project

Enhanced recovery efforts of the Gordon sandstone have been undertaken almost since its discovery. These efforts took the form of re-injecting the gas that was collected from the gas-oil-water production stream. Field records of these projects are not available and only literature citations of these activities are available from State Geological Surveys bulletins. The first recorded instance of secondary recovery in the Gordon formation was in 1923, when gas drive or repressuring yielded oil recoveries as high as 100 bbl per acre-foot. By 1967, 14 gas injection projects were underway in this field (Harper, 1987), but only one of them took place in the unit studied. For the purposes of this study, gas injection was considered and tuning of the reservoir model incorporated its impact. A more rigorous treatment of its impact could not be implemented due to the lack of available historical data.

During February 1982, a waterflood injection pilot was initiated. It consisted of two contiguous five-spot patterns located in the southeastern portion of the unit. Its location is shown on Figure 2.3, and pilot project lasted almost 7 years. During the 7 years period, 1.2 MM bbl of water was injected into the reservoir. The effect of this water injection was realized in two wells that are located outside the injection pilot pattern. These wells are the J. Hodgens 9 and J. Hodgens 10, and are located about 1000-ft to the west of the pilot. The production from these two wells was comparable to that from the wells located in the water flood injection pilot area that produced 6.4 Mbbl of oil.

Other implications of the pilot project are:

1. The injection water impacted the performance of the reservoir by altering the saturation distribution in the southern portion of the unit.
2. The pilot proved that the unit's reservoir possesses the petrographic characteristics necessary to sustain a waterflooding project.

In March of 1996, the unit-scale water injection project began. The waterflooding project consisted of 11 injection wells located in a line-drive pattern (see Figure 2.3). The initial injection rate was 4500 bbl/d of water and declined to approximately 800 bbl/d with a cumulative volume injected of approximately 5 MMbbl (see Figure 2.5). The water injected was initially from unconventional sources of water such as coalmine water and formation brine. By December 1999, fresh water injection from a municipal water company started. The fresh water is treated with chemicals to reduce its adverse impact on formation clays (clay swelling).

The locations of the injection wells are toward the center of the reservoir, where the properties of the sand are the most favorable to the process, i.e. the thickness of the reservoir is the greatest and the formation is the deepest (higher injection pressures). The principal disadvantage of this pattern design is that distance between the injection and production wells is large, and consequently the flood front requires additional time to affect the production wells and the swept oil must be displaced a longer distance to the producing well. Also, producing wells are generally located where the formation is the thinnest, which is toward the eastern and western flanks of the reservoir. Coincidental to movement of water towards the flanks of the reservoir, resistance to its flow increases. This is expected given that as the formation thins, rock properties such as permeability and porosity decrease.

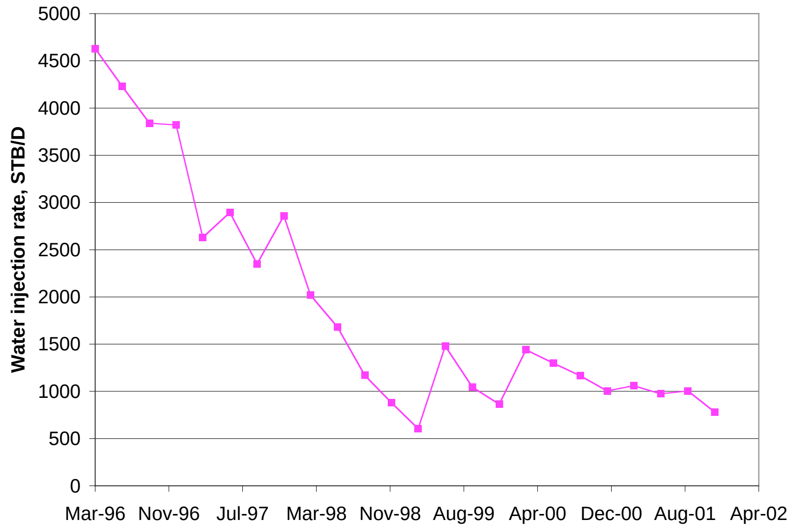


Figure 2.5: Washington-Taylorstown field, total water injection rate.

2.2 Fluid properties

Due to the lack of information about the reservoir fluid properties, several correlations and assumptions were used to develop a thermodynamic and physical black-oil model capable of simulating the behavior of the reservoir fluids under the various operating conditions. Little information is available to estimate the physical properties of the reservoir fluids. The properties known include an oil API gravity of 40° (Lytle, 1950), and bubble point pressure of 780 psia (Pennzoil, 1985).

There is no information about the composition or properties of the gas present in the Taylorstown reservoir. The specific gravity of this gas was determined to be 0.9 using a gas chromatographic analysis. Gas Analysis Systems Inc performed this analysis, in June 2001. The water specific gravity was assumed constant and equal to 1.0, and the gas phase was assumed immiscible in the water phase. Also, it was assumed that the temperature of the reservoir remains constant at all times.

Given the sparse information known about the properties of the fluids present in this field, a PVT model was developed using published correlations. The PVT model developed is a black-oil model, with the capability to simulate dissolved gas in the oil phase.

The PVT model requires the determination of certain properties at different pressure conditions. For the oil phase, these properties were: solution gas-oil ratio (R_s), oil formation volume factor (B_o), oil compressibility (c_o), and oil viscosity (μ_o).

The solution gas-oil ratio at different pressures was estimated using a correlation developed by Glaso in 1980. This correlation is shown below:

$$R_s = \gamma_g \left[\frac{API^{0.989}}{T^{0.172}} 10^Y \right]^{1.22549}$$

where:

$R_s =$ solution gas-oil ratio, SCF/STB$_O$

T = temperature,°F

API = oil API gravity

γ_g = specific gravity of the gas at standard conditions

and Y is defined as follows:

$$Y = \frac{1.7447 - \sqrt{5.1797 - 1.2087 * \log(p)}}{0.6044}$$

where:

p = pressure, psia.

The oil formation volume factor was determined using the following correlation developed by Standing:

$$B_o = 0.972 + 0.000147 F^{1.175}$$

where:

B_o = oil formation volume factor, bbl/STB$_O$

The F factor is determined using the following equation:

$$F = R_s \sqrt{\frac{\gamma_g}{\gamma_o} + 1.25T}$$

where:

R_s = solution gas-oil ratio, SCF/STB$_O$

T = temperature,°F

γ_g = specific gravity of the gas at standard conditions

γ_o = specific gravity of the oil at standard conditions

The oil compressibility was determined by means of the Vazquez and Beggs correlation shown below:

$$c_o = \frac{-1433 + 5R_s + 17.2T - 1180\gamma_{gc} + 12.61API}{10^5 p}$$

where:

c_o = oil compressibility, psi^{-1}

R_s = solution gas-oil ratio, SCF/STB$_O$

T = temperature,°F

API = oil API gravity

γ_g = specific gravity of the gas at standard conditions

γ_o = specific gravity of the oil at standard conditions

p = pressure, psia

Finally, the oil viscosity was estimated using the Beggs & Robinson correlation.

The viscosity of the live oil is determined by:

$$\mu_{ol} = \left(10.715(R_s + 100)^{-0.515}\right)\mu_{od}{}^{b}$$

where:

μ_{ol} = viscosity of the live oil, cp

μ_{od} = viscosity of the dead oil, cp

R_s = solution gas-oil ratio, SCF/STB$_O$

The *b* factor is calculated by the following equation:

$$b = 5.44\left(R_s + 150\right)^{-0.338}$$

The viscosity of the dead oil is estimated using the correlation shown below:

$$\mu_{od} = 10^{x} - 1$$

where x is calculated as:

$$x = \frac{10^{\left(3.0324 - 0.02023 API\right)}}{T^{1.163}}$$

For the water phase the only properties estimated at different pressures were the water formation volume factor (B_w), the water compressibility (C_w), and the water viscosity (μ_w). The water formation volume factor was estimated by means of the Gould correlation:

$$B_w = 1.0 + 1.2x10^{-4}\left(T - 60\right) + 1.0x10^{-6}\left(T - 60\right)^2 - 3.33x10^{-6}\,p$$

where:

B_w = Water formation volume factor, bbl/STB$_W$

T = temperature,°F

p = pressure, psia

The water compressibility was calculated using the Meehan correlation for gas free water.

$$c_w = 10^{-6}\left[A + BT + CT^2\right]$$

where:

c_w = water compressibility, psi^{-1}

T = temperature,°F

and the variables A, B, and C are defined as:

$$A = 3.8546 - 0.000134p$$
$$B = -0.01052 + 4.77x10^{-7}\,p$$
$$C = 3.9267x10^{-5} - 8.8x10^{-10}\,p$$

where:

p = pressure, psia

The water viscosity is estimated by means of the Beggs & Brill correlation, shown below:

$$\mu_w = \exp\left(1.003 - 1.479x10^{-2}\,T + 1.982x10^{-5}\,T^2\right)$$

where:

μ_w = water viscosity, cp

T = temperature,°F

For the gas phase, there was the need to determine the gas compressibility (B_g), and the gas viscosity (μ_g) at various pressures. The formation volume factor was determined using the real gas equation of state, where:

$$B_g = 0.0283\frac{ZT}{p}$$

where:

B_g = gas formation volume factor, Cf/SCF

T = temperature,°R

p = pressure, psia

z = gas compressibility factor

To calculate the viscosity of the gases, the Lee et al. correlation (1966) was employed. This correlation is shown below:

$$\mu_g = K \times 10^{-4} \exp\left[X\left(0.0433\rho_g \frac{p}{Z(T+460)}\right)^Y\right]$$

where:

μ_g = gas viscosity, cp

T = temperature,°R

p = pressure, psia

z = gas compressibility factor

The variables K, X and Y are defined as follows:

$$K = \frac{(9.4 + 0.02M_a)(T+460)^{1.5}}{209 + 19M_a + (T+460)}$$

$$X = 3.5 + \frac{986}{(T+460)} + 0.01M_a$$

$$y = 2.4 - 0.2X$$

where:

M_a = Molecular weight of the gas.

Even though the fluid properties available to build the model were sparse, the correlations and assumptions employed allowed building a complete PVT model that is able to simulate the behavior of the three phases involved in the reservoir.

2.3 Rock properties

The rock properties needed to perform this simulation study are: porosity, initial saturations, absolute permeability, relative permeability, and capillary pressures characteristics. The porosity in different locations of the field was determined using pore-feet maps provided by the operator of the field. This pore-feet map allowed estimating the porosity in the center of all the grid blocks of the field. The porosity values discretized ranged from 16% to 35%.

A gas saturation map was provided, and it was used to define the initial gas saturation of each grid block at the beginning of the waterflood operations. The only information available to estimate the water saturation of this field was 12 resistivity logs, which were obtained from the 12 injection wells. These logs showed that the water saturation in the injection wells ranged from 12% to 32%, with an average of 20%. The location of the measurements of water saturation did not allow interpolating the saturation values towards the boundaries of the field; therefore, a value of water saturation of 20% was initially assumed for the entire reservoir.

There was one core analysis available for use in the Taylorstown study: Core laboratories performed the analysis on a core obtained from the John Mc Mannis 1 Well. The information provided in this core analysis was used to feed the simulator with an estimate of the absolute permeability, relative permeability (Figure 2.6), and capillary pressure for this sandstone (Figure 2.7).

The arithmetic average absolute permeability that was determined using the core analysis is 100-md. Since this core analysis was the only one available for the field, the absolute permeability obtained was used to initialize all blocks in the simulator.

The relative permeability curves obtained from the core analysis (Figure 2.6) show that for values of water saturation below 30%, the relative permeability of the displacing phase (water) has values below 0.001. The low relative permeability of the water suggests that the mobility of the displacing phase is small. Given this, the model was unable to simulate the water injected in the field.

Several preliminary runs were made to determine if relative permeability values obtained from the core analysis are representative of the field wide permeabilities. Results indicated that a satisfactory match of field behavior was not attainable. Given this, another approach was necessary. The relative permeabilities curves obtained from the analysis of a core taken from the L.S. Hoyt 100 well (LSH 100) in the Wileyville field were tested for applicability (Figure 2.7) The justifications for this approach are that both the Taylorstown and Wileyville fields are geographically near one another, and produce from the same reservoir, the Gordon Sandstone.

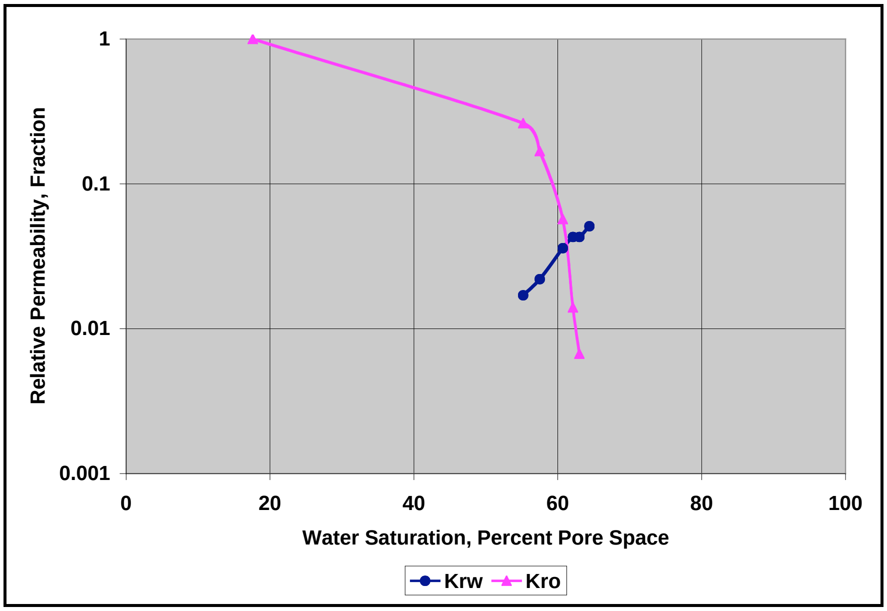


Figure 2.6. K_r vs. Sw (John McMannis 1 Well, Taylorstown Field)

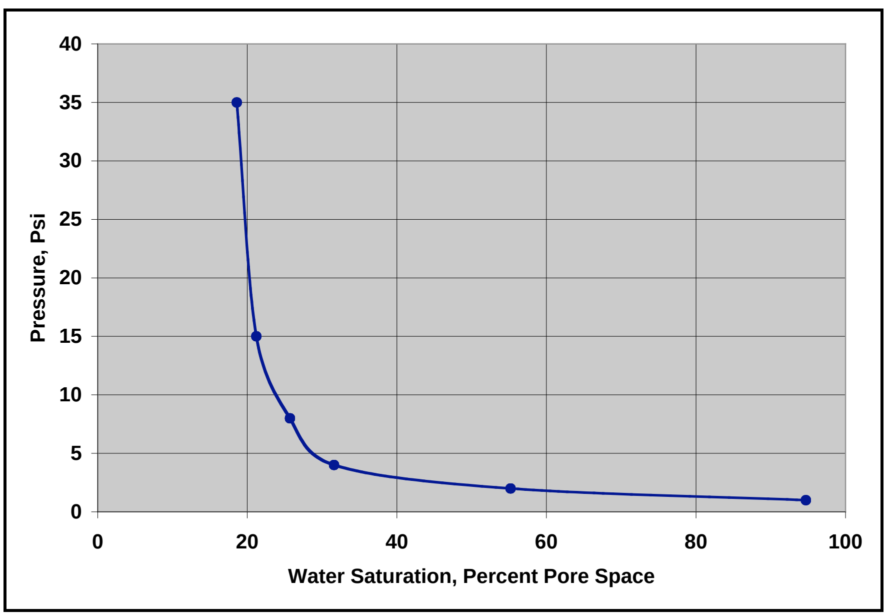


Figure 2.7. Capillary pressure vs. S_w. (James McMannis 1 Well, Taylorstown Field)

3.0 RESULTS AND DISCUSSION

After the initialization of the data, the model is run to determine the similarity between the trend and value of the results of the simulation and the data obtained from the field. The results of this first run indicate the regions of the reservoir where the assumptions made can be considered to be a "good" approximation, and give the modeler a hint about the properties that must be adjusted in order to make the simulation match the behavior of the field. It is the good initialization of the reservoir properties along with a clear description of the history of each field that allows an efficient history matching process and the best representation of the actual behavior of the reservoir.

Given the sparsity of the data available for the construction of the models of this study, several assumptions and correlations were made. The most critical assumptions are:

1. These reservoirs could be modeled as two-dimensional single layered models with uniform properties throughout the thickness of the sand,
2. Extrapolation of fluid and rock properties from studies made in other fields within the same basin where the Gordon sandstone is undergoing waterflooding,
3. Application of a black-oil model based on published correlations using only the specific gravity of the oil and gas present in this field.

The guidelines for history matching are applied to the Washington-Taylorstown field. This section of the chapter discusses the results obtained from the initialization of the parameters, the results of the history matching, and the results of the predictive phase of the study for the Washington-Taylorstown field.

3.1 Results of the initialized model

Figure 3.1 compares the results of the actual and simulated field water injection rates for the first run following the initialization of the study. As the plots indicate, the shapes of the simulated and the actual curves are similar. This similarity validates the general trend in the behavior of water injection in the model. In addition, Figure 3.1 shows that the water injection decline is at a higher rate than that expected if uniform permeability is assumed throughout the reservoir. The abrupt changes in injection rate coincide with the dates when workovers were undertaken. These changes reflect the positive impact on the injectivity of the field of individual well workovers.

Figure 3.2 compares trends of the simulated cumulative production after the initialization of the model to the actual production observed in the field. It shows that the trend of the simulated curves is similar to the trend of the cumulative production observed in the field. This validates the ability of the model to recreate the production trend of the field. The results observed for each well permitted the identification of the regions of the model where the permeabilities and or the saturations need to be adjusted to make the model match the actual behavior of the field. The results of this run revealed that for most wells the cumulative liquid production has a similar behavior, even though the cumulative production of each phase does not approximate the value expected.

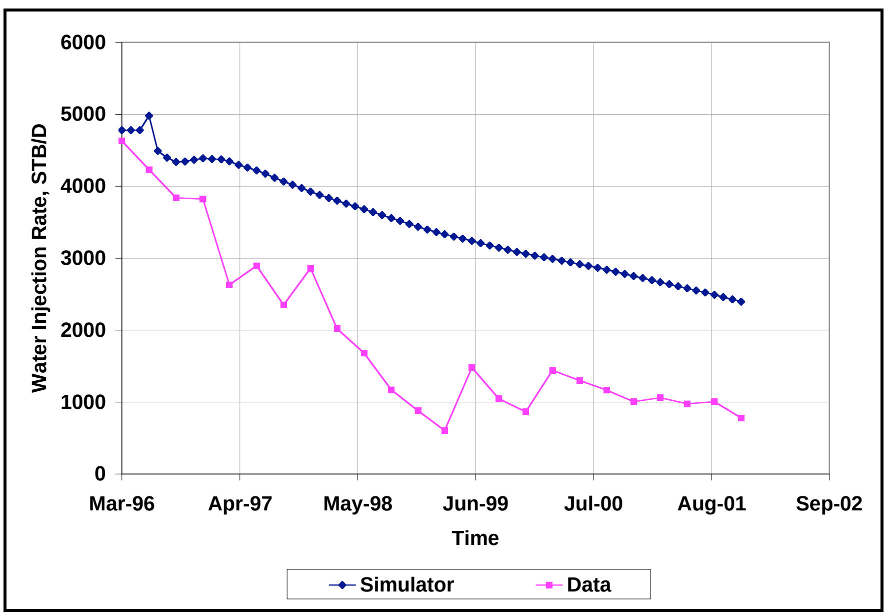


Figure 3.1. Field water injection rate vs. time. Field data vs. simulation results.

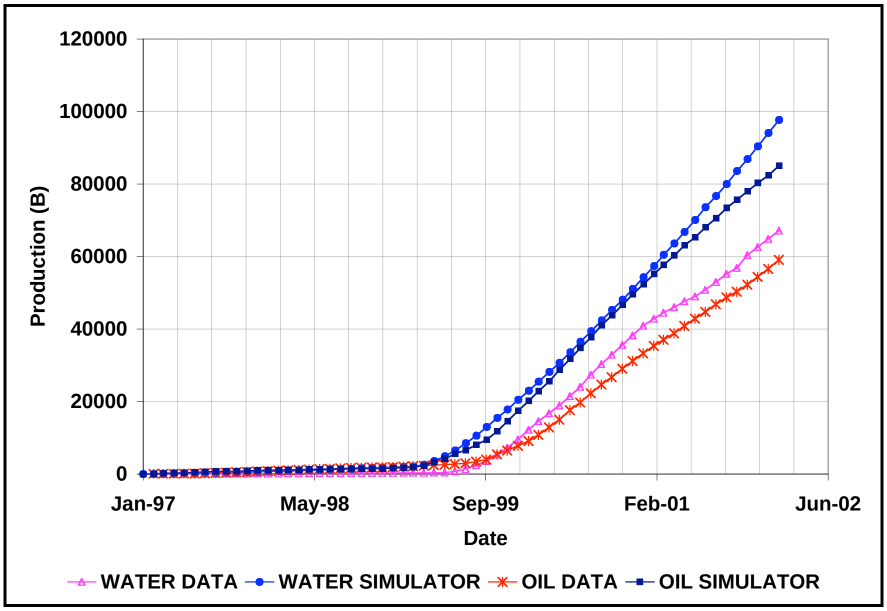


Figure 3.2. Field cumulative production vs. time. Field data vs. simulation results

Even though the results of the individual wells do not match the behavior shown in the field in terms of oil and water cumulative production, initialization of the model using the sparse information available has proven to be an acceptable starting point for the history matching. As indicated earlier, this initial approximation provides the basis for identifying the parameters that need to be changed and their field location.

3.2 History matching results

After several iterations during which the "unknown" parameters in the model were adjusted, a satisfactory history match was achieved. The results show an acceptable behavior of the model, which mimics the operations of the field since the beginning of the waterflooding, during February of 1982, to the end during January of 2002. The results of the history matching are analyzed in this section.

3.2.1 Discussion of the results of the injection match

The comparison of the actual and the simulated water injection rates confirm that the trends of both curves are qualitatively similar for all injection wells. Figure 3.3 shows that the simulated water injection rate curves are similar in shape and trend to the actual water injection curve for every well. In addition, it can be seen that the simulated water injection rate on a field scale is in good agreement with the actual water injection curve of the field.

The second step in the analysis of the results is to compare the actual and the simulated water injected volumes for each well. These volumes are computed for the actual operation and for the simulation, and the results compared. Figure 3.4 shows the difference between the actual and the simulated water volumes for each injection well. The relative error in the water-injected volumes is calculated for every well and the results reported in Figure 35. In this figure it can be seen that the error in 11 of the 12 injection wells is below 18%, which is considered to be “acceptable” for this study.

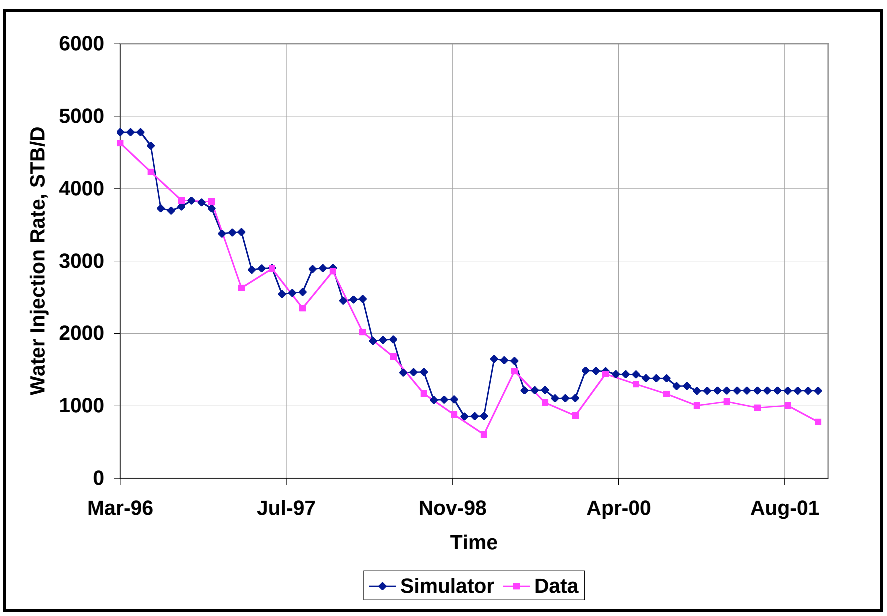


Figure 3-3. Field water injection rate vs. time. Field data vs. simulation results

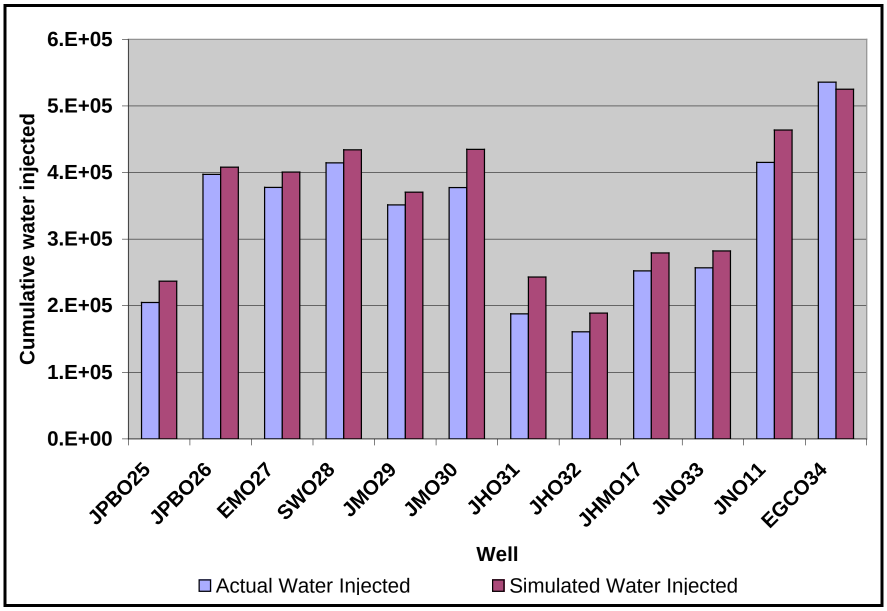


Figure 3.4. Comparison of the water injected volumes. Field data vs. simulation results

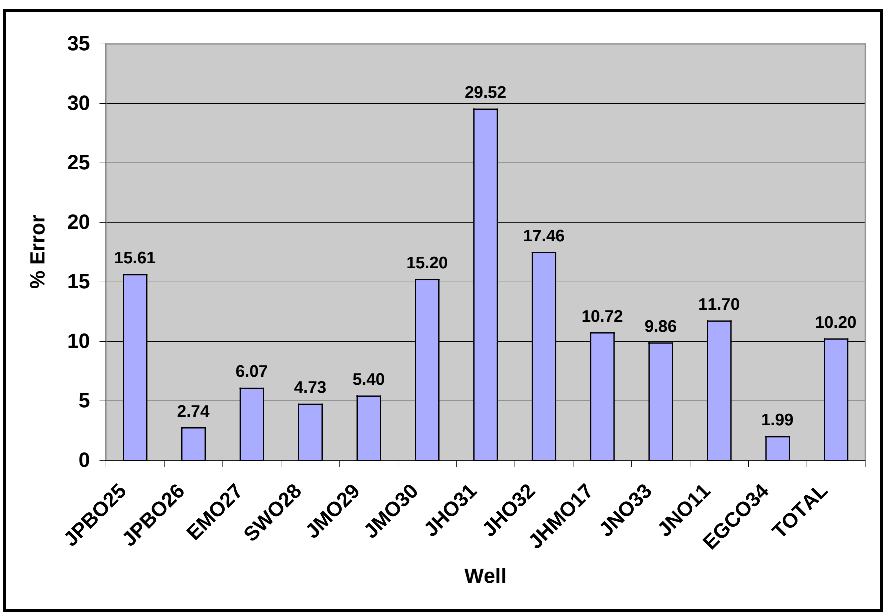


Figure 3.5. Relative error computed for the water volumes injected

The James Hodgens 031 (JHSR 031) well is the only well where the error is greater than 18%. However, the absolute difference between actual and the simulated water volumes injected by this well is small (about 55,000 barrels). When compared to the volume injected in the field, this represents only about

2% of the total water volume injected; therefore this error is considered to be not significant. The total water injection of the field is within a 10% error, which is considered to be an acceptable match for this study.

3.2.2 Discussion of the results of the pressure match

Table 3.1 shows that all the pressures calculated by the model match the pressures obtained from the field, within an error margin of 20%. As previously noted, fluid levels were calculated using an acoustic device. The error associated with this measurement include imprecise fluid height and lack of knowledge of column density. As a consequence, an error of 20% was determined to be reasonable.

Only two pressures calculated in the simulation are not within this margin of error. These pressure readings correspond to Samuel Woodburn 11 (SW 11) and James Paul Bigham 4 (JPB 4) wells. The behavior of these wells shows an abrupt decline in the fluid level readings and liquids production. It was concluded that the wellbores of these wells might be damaged and the skin factor of such magnitude suggested that there was no communication with the reservoir sand. Therefore, the measured data were considered to be unrepresentative of the pressure conditions present in the reservoir.

Even though the error computed for the James Hodgens Sr. 10 (JHSR 10) and J. A. Flack 3 (JAF 3) wells is greater than the margin of error, the absolute difference in the pressure values is not significant (about 60 psi), and this difference might be attributed to the resolution of the instruments used to read the fluid levels in the field.

WELL	LOCATION	DATE	REAL	SIMULATED	ERROR (%)	COMMENTS
JH1	9,32	Dec-99	386	340	11.92	
JN2	9,30	Dec-99	500	472	5.60	
JPB4	7,9	Dec-99	92	183	98.91	BLOCKED
SW11	6,15	Dec-99	37	132	256.76	POSSIBLY BLOCKED
EM1	10,12	Dec-99	190	201	5.79	
JN3	7,29	Dec-99	400	447	11.75	
JHSR9	8,36	Oct-01	256	243	5.08	
JHSR10	10,38	Oct-01	276	202	26.81	
JAF3	9,39	Oct-01	240	187	22.08	

Table 3.1. Actual pressures measured vs. Pressures simulated

3.2.3 Discussion of the results of the production match

Figure 3.6 compares the actual and the simulated cumulative production of oil and water respectively. The trends of the actual and the simulated curves are similar in both shape and value, giving a good qualitative match. The simulated and the actual oil and water production of each well is also similar in both shape and value, resulting in a good match.

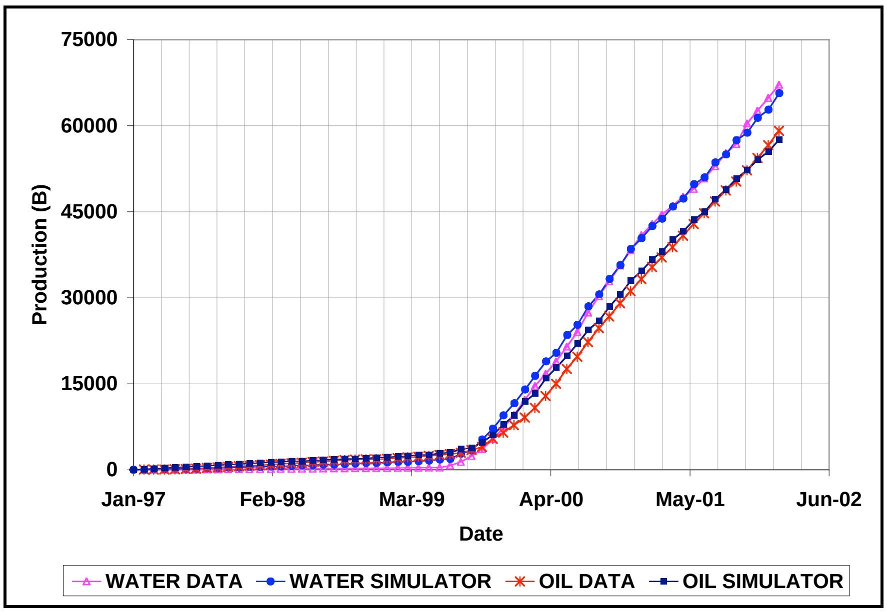


Figure 3.6. Oil and water production of the field vs. time. (Field data vs. sim. results)

Figure 3.7 indicates that the error in the match for the cumulative oil production for each well is less than 10% for most of the wells. In addition, in those wells where the error is greater than 10%, the difference in the oil production is not significant when compared to the total oil production of the field (Figure 3.8). The error in the most prolific wells (J. A. Flack 1 (JAF 1), and V.M. Blayney 22) is less than 10%.

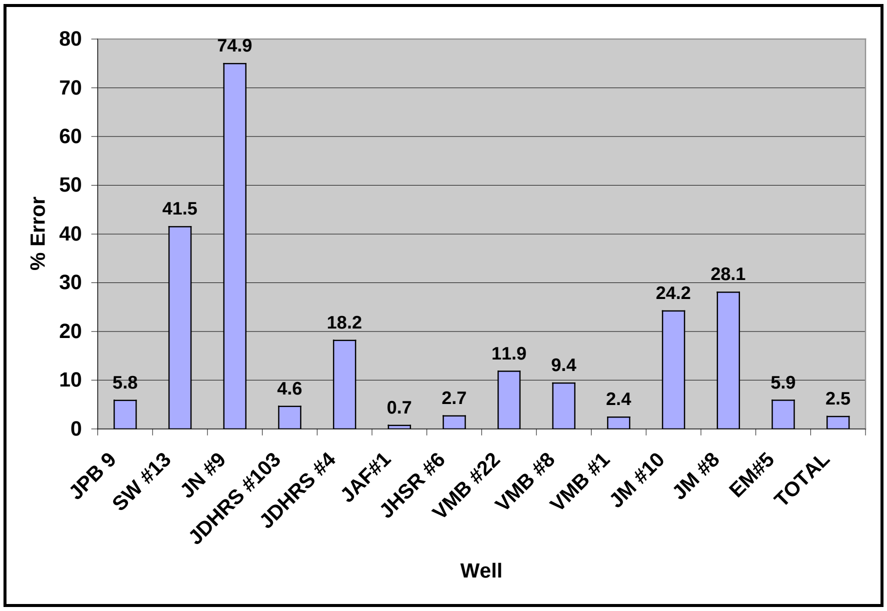


Figure 3.7. Error in the cumulative oil production per well

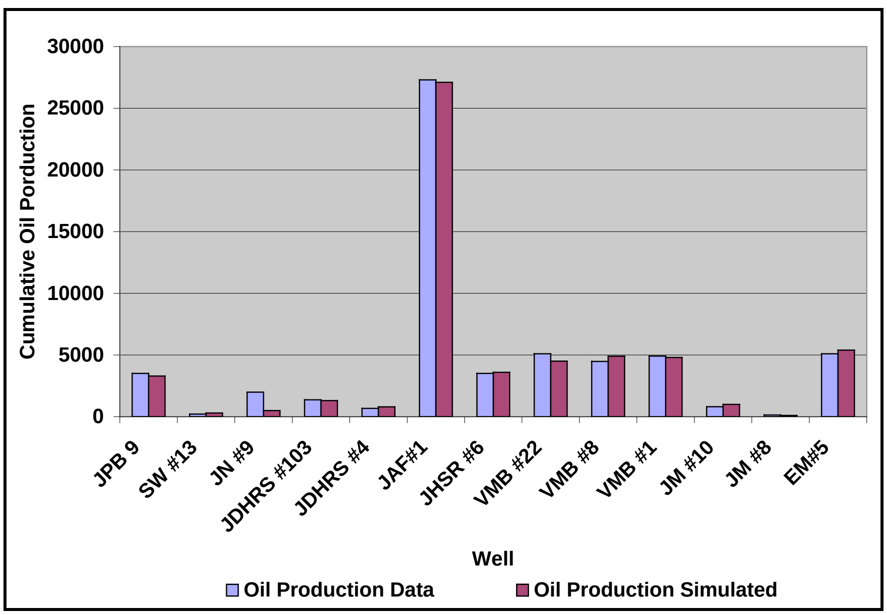


Figure 3.8. Comparison of oil production per well (February 2002)

The deviation in the oil production is less than 10% for 8 of the 13 wells, in three wells (JDHRS 4, JM 10, and JM 8) the disparity was slightly higher than 10% (around 20 %), and the only wells showing a significant disparity are wells James Noble 9 (JN 9) and Samuel Woodburn 13 (SW 13). In any case, the production of these wells is small and it is not significant when compared to the production rates of other wells in the field. Figure 3.8 compares the actual and simulated cumulative oil production per well. The results show good agreement between the predicted and observed values for each well. In addition, it shows that even though the error is greater than the “acceptable” for wells JN 9, SW 13, JDHRS 4, JM 10, AND JM 8, the difference between the volumes produced and predicted through simulation is small in terms of absolute production. For these wells, the differences in the volumes actually produced and simulated are explained by the fact that production is intermittent. As a consequence, the actual production does not have the “exact” production schedule as that predicted through simulation.

The error in the predicted water production is less than 10% for 10 of the 13 wells (Figure 3.9). This is considered to be an acceptable error, given the fact that the actual production and the simulated production did not have the same production profile. Figure 3.10 is used to compare the actual and the simulated cumulative water production per well. Figure 3.10 shows that the actual cumulative water produced is similar to the predicted from simulation for each well. In addition, it shows that even though the error is greater than “acceptable” for wells JPB 9, and EM 5, the difference between the volumes produced and simulated is small when compared to the total water production. For these wells the difference in the volumes actually produced and that predicted through simulation is explained by the fact that production is intermittent, and consequently actual production schedule is not an exact replication of the production schedule used in the simulation.

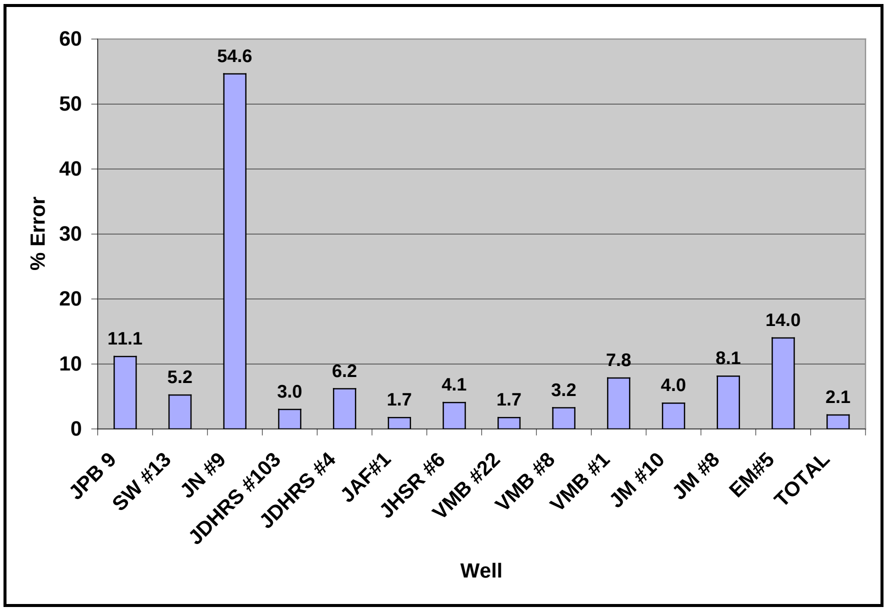


Figure 3.9. Error in the cumulative water production per well

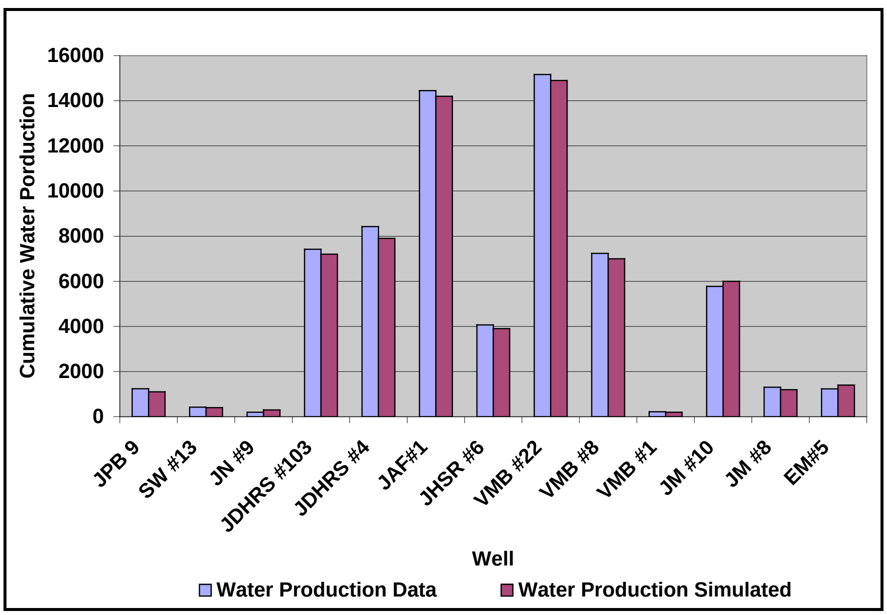


Figure 3.10. Comparison of water production per well (February 2002)

Only one well shows a significant error in the cumulative water produced, James Noble 9 (JN 9) well. This well shows a deviation because it underwent a workover on November 2001, and the data indicate a sudden increase in oil and water production. The trend during recent months is not of sufficiently long duration for matching to be attempted for this well. Nevertheless, the simulation could not match the sudden increase in additional oil production. This was because the workover of this well resulted in a significant decrease in the near wellbore damage and the model could not approximate this behavior. This increase in production amounted to 1,500 barrels that represents only about 2% of the total oil volume produced. This is not significant when compared to the total oil production of the field.

When the history match is considered to be acceptable, the results of the simulation are representative of the past and present behavior of the reservoir. Observations were then made about the impact of the multiple sources of water on the injection and the influence of the water injected during the injection pilot on the current production of the field.

3.3 Discussion on skin damage

Skin is a mathematical representation of formation damage or stimulation and represents a decrease or increase in apparent permeability. Physically, damage can result for a variety of reasons such as clay swelling and/or fines migration. In the case of fluid injection as in secondary recovery, the cause of this damage may be the precipitation of unfiltered solids or injected fluids-formation incompatibility. Dynamic skin reflects the variation of this formation damage with time and represents the physical reality of well operations over time.

In this study, the analysis of the dynamic skin is undertaken in the context of waterflooding and it is determined during the history matching process through inference. This is accomplished by varying the values of S, skin factor, to match well and field performance. To analyze the change in S with time, plots needed to be constructed and analyzed.

The case study involves the Washington-Taylorstown field. The analysis is carried out in two steps. First the dynamic behavior of the skin in the injection wells, where this effect is more pronounced, is initially addressed. The phenomenon is then extended to the production wells. Since the movement of the fluids starts in the injection wells and moves toward the production wells, analysis of the skin factor in the two types of wells will provide quantitative information on the time dependency of skin damage.

To accomplish this analysis, the Washington-Taylorstown field was subdivided into regions. The criteria employed in the classification of the different regions were: 1) the type of well, either injection or production, 2) the physical location of the well and, 3) the similarity in the dynamic skin behavior in the well. Figure 3.11 shows the regions for the case study. Historical injection and production rates were constructed and analyzed for each region. The results obtained are discussed below.

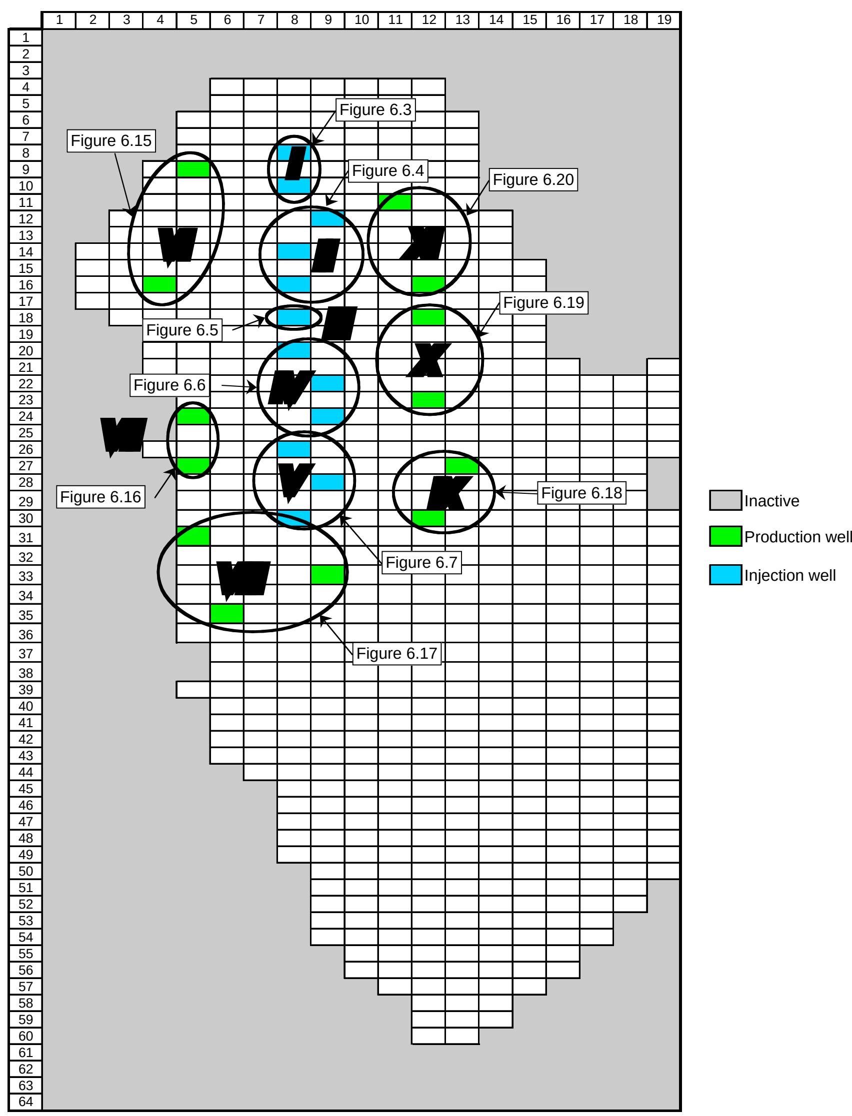


Figure 3.11 Washington-Taylorstown field regions.

As indicated earlier, the Washington-Taylorstown field has been subjected to waterflooding since February 1982, when an injection pilot located in the southern portion of the field was developed. Based on the results of this pilot project, it was concluded that this reservoir had potential for waterflooding. This conclusion was based on the fact that suitable injection rates were achieved and production responses were noted in nearby wells. Based on the results of the pilot, field scale flooding was undertaken.

3.3.1 Discussion of the results on skin damage in injection wells

Field scale waterflooding using a line-drive pattern began in March 1996. From March 1996 until March 1999, the water used for the injection was obtained from an abandoned coalmine and/or produced brine from gas fields operated in the area. One potential problem with the use of water from unconventional sources of water is the potential for reservoir damage attendant to the transport of the unfiltered solids into its matrix. Added to this is the fact that incompatibility of the formation fluids with the injection fluid can potentially create chemical reactions in the matrix. Chemically treated freshwater injection began in March 1999, and has continued to the present.

As the plot indicates (Figure 3.12), the injection history is broken into two periods. During Period I, the source of the water injected was from an abandoned coalmine and brine from a gas producing formation. This practice ended in March 1999. During Period II, the source of injected water was from a municipal water system. As previously indicated, this water was treated with a chemical to minimize its impact on the formation.

During the first injection period, the injectivity of the field declined from 4.6 Mbbl/d to 600 bbl/d. It is noted that during this period, efforts were made to improve the water injection rates. The loss in injectivity is attributed to the following factors:

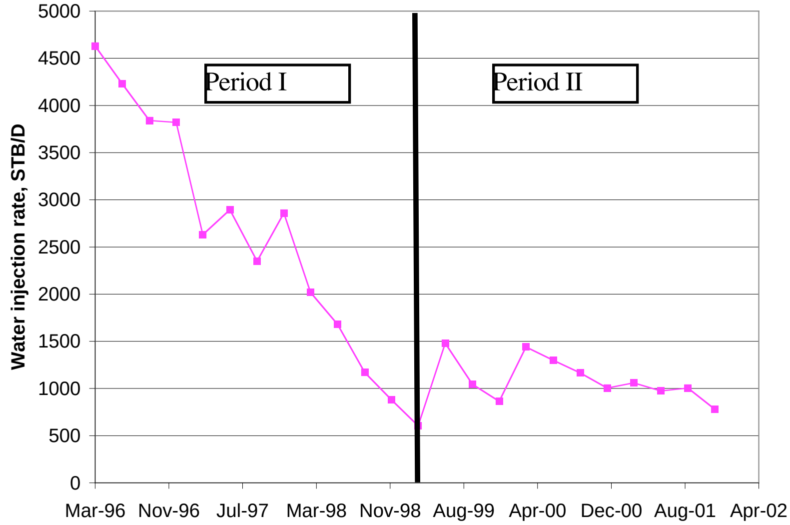


Figure 3.12: Washington-Taylorstown field, periods of water injection.

1) Natural fill up that is attendant to liquid injection.

2) Fill up resulting from the introduction of unfiltered solids.

3) Fill up resulting from the formation of a viscous sludge, i.e. emulsions.

4) Blockage of pore space throats that reduces the formations absolute permeability near the wellbore.

The erratic behavior of the injection rate with time suggested wellbore skin problems. Consultation with the operator, however, indicated that efforts were made to alter this behavior by well workovers, stimulations and chemical treatments. As the results on Figure 3.12 indicate, the effects of these treatments were short-lived.

To better understand the injectivity problem, the Washington-Taylorstown field was divided into eleven regions. Five of the eleven regions contain the 12-injection wells and the other six the 23-production wells. The locations of the eleven regions are shown on Figure 3.11. Figures 3.13 to 3.17 contain plots of the skin damage versus time and the water injection rate for each of the injection wells found in regions I though V. Each of the figures indicates a decrease in injection rate with time. The operator's effort to reverse this decline in injectivity through acidizing resulted in a short-lived increase in injectivity followed by a decrease.

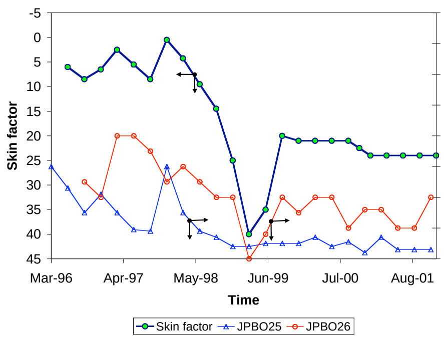


Figure 3.13: Skin factor in injection wells JPBO25 and JPBO26 of Washington-Taylorstown field.

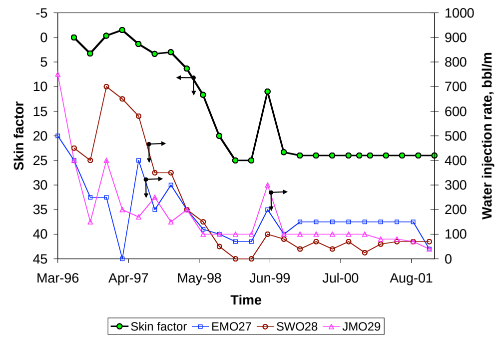


Figure 3.14: Skin factor in injection wells EMO27, SWO28 and JMO29 of Washington-Taylorstown field.

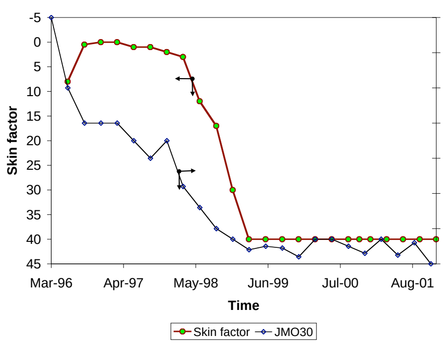


Figure 3.15: Skin factor in injection well JMO30 of Washington-Taylorstown field.

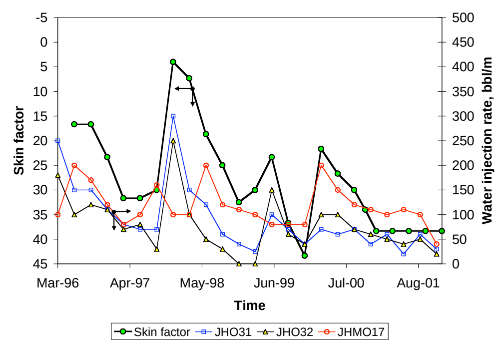


Figure 3.16: Skin factor in injection wells JHO31, JHO32and JHMO17 of Washington-Taylorstown field.

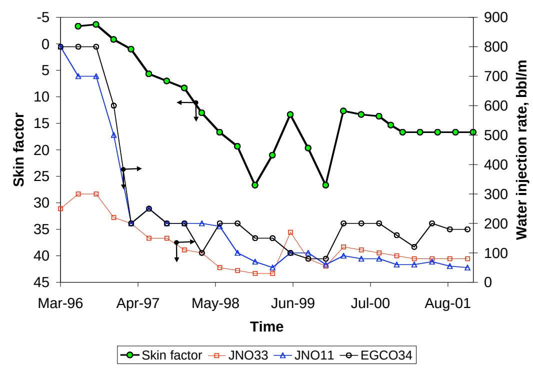


Figure3.17: Skin factor in injection wells JNO33, JNO11 and EGCO34 of Washington-Taylorstown field.

This cycle of well stimulation followed by a decline in injection rates was repeated until the start of fresh water injection (by mid 1999 and early 2000). Even though injection rate continues to decline with the switch to fresh water, the rate of decrease is smaller (see Figure 3.12). During Period II, it should be noted that the operator undertook a series of workovers and acidizing jobs. This combined with the use of treated water resulted in a field-wide increase in injectivity. The field injection rate had dropped to 600 bbl/d prior at the start of fresh water injection. The injection rate increased to 1.4 Mbbl/d. However after 6 months, the injectivity decreased again to 860 bbl/d. After acidizing the wells of higher injectivity, the field injection rate again increased up to 1.4 Mbbl/d. Since then, a general and steady decline in the injection rate has been reported reaching today's value of approximately 700 bb/d.

The skin factor coincidental to the use of treated fresh water has stabilized (see Figures 3.13 to 3.17). Efforts to decrease the skin were unsuccessful because the damage resulting from the use of unconventional water (coal mine – brine) and air flooding was spread throughout the reservoir. What is envisaged with respect to this process is shown on Figure 3.18. The concept suggested is one where stimulation of each well penetrates further and further from the wellbore; but the damaged zone is so pronounced that its effect on injection rate is soon felt.

In addition to the change of water source there are other variables to consider that may affect the skin. At the beginning of the 20th century, this field was subjected to gas-air flood stimulation. With the presence of oxygen in the reservoir, chemical reactions may take place leading to the production of emulsion, which may promote blockage of the reservoir. Besides, the oxidation of the metallic elements in the injection wells is expected to precipitate ferric compounds, which may also be deposited in the reservoir.

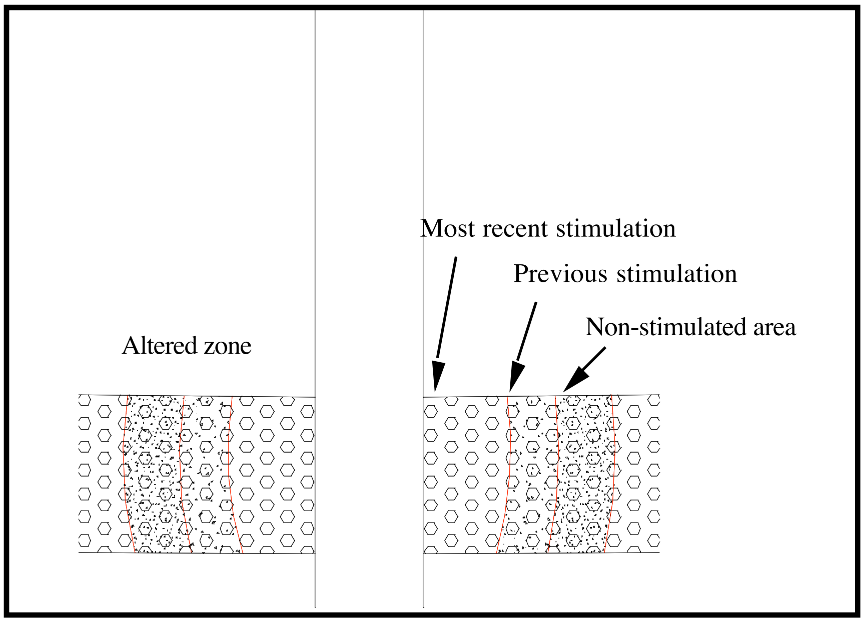


Figure 3.18: Formation skin damage after cyclic stimulations.

For Period II, 1999 to today, each of the injection wells possesses a similar performance as it is described at the field scale. Wells JPBO25 and JPBO26 (Figure 3.13) and wells EMO27, SWO28 and JMO29 (Figure 3.14) show reduced skin damage that coincides with acidizing and the use of treated fresh water for injection. It should be noted that two stimulation jobs were performed after the initiation of fresh water injection. The first was after 3 months and the second after 9 months. In both cases, the skin damage was reduced, but with time increased and stabilized at values of approximately 25. As was expected, injectivity behaved in an opposite manner. The trend following stimulation indicated an increase followed by a decrease and then stabilization at a lower value.

Wells JHO31, JHO32 and JHMO17 (Figure 3.16) and wells JNO33, JNO11 and EGCO34 (Figure 3.17) showed a better response to the change of the injected water. The impact of skin factor showed improvement through reduction immediately following the stimulation jobs. However after 3 to 4 months, skin damage increase was evident as reflected in the decrease in injection rates.

The behavior of well JMO30 (Figure 3.15) is unusual when compared to other injection wells in the field. The change of injected water did not affect the behavior of the well, even though stimulation jobs have been performed. This response is attributed to the location of the well in the region with poor properties that separates the northern and southern portions of the field. Although treated water is now being injected, the effect of the deposited particles from the untreated water continues to be felt. It is thought that the injection rate will steadily drop even with additional stimulation.

3.3.2 Discussion of the results on skin damage in production wells

Production well behavior as would be expected is different than injection well behavior. This is because liquid production is dependent on the location of the flood front as it moves throughout the reservoir and the saturation distribution present in the vicinity of the production well. Each well behaves in a unique fashion and as a consequence, no generalization concerning production behavior can be made. In this field, wells J.A. Flack 1, V.M. Blayney 1, V.M. Blayney 8, V.M. Blayney 22 and J.P. Bigham 9, are the principal liquid producers. Other production wells in the northern and western portions of the field produce little or no liquid. In the case of the wells located in the northern section, the presence of the high gas saturation precludes liquid production and in the case of the wells located in the west, the flood front has not yet arrived. The focus of this analysis in terms of skin is the liquid producing wells or those where liquid production can be realized through workovers.

The production of oil and water at the field level increased in late 1999. This increase in production was coincidental to the start of treated fresh water injection. This observation is based on the presupposition that fill up of the reservoir was mainly completed and that displacement of both reservoir oil and formation water had reached several of the production wells. In wells SW13, JDHRS103, JDHRS4, JHSR6, JM10, JM8 and EM5, breakthrough had occurred with a resulting production of mostly water. In wells JAF1, wells JAF1, VMB1 VMB8, VMB22 and JPB9 breakthrough has not occurred and as a consequence, production of both oil and water are realized.

Figure 3.19 shows the water saturation as of March 2002. The figure indicates that wells JN9, JDHRS4 are located in areas of high water saturation and as expected produce mostly water. Wells JAF1 and JPB9 are located in areas where the oil saturation is high and produce both oil and water.

As previously indicated, the injected water is displacing particles in suspension toward the production wells. As a consequence the production of the wells is being affected by the particle displacement. The analysis indicates that skin resulting from the displacement increases prior to the onset of displaced water. Prior to the arrival of these displaced liquids, the skin damage was in the range of 0 to 5. With breakthrough, these values increased to a range between 40 and 50. It should be noted that this effect is long lasting and the efforts to reverse it through reconditioning of the wellbore result in only short lived increases in productivity (approximately 3 months) and that the production then begins to experience a pronounced decline.

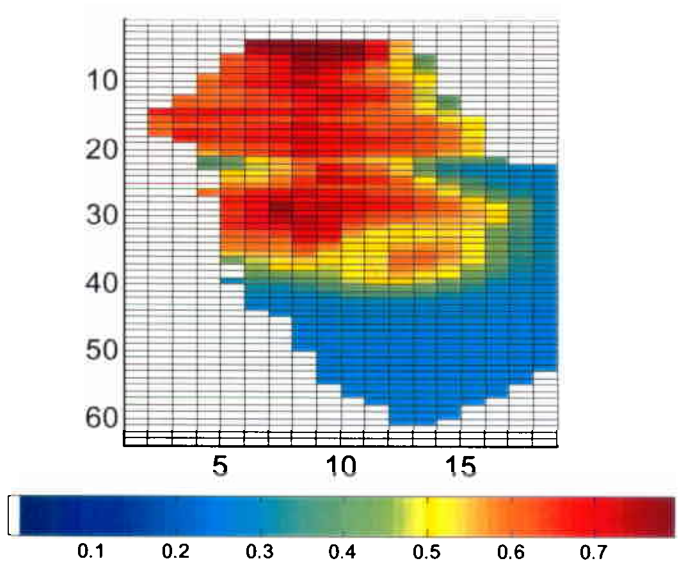


Figure 3.19: Washington-Taylorstown field, water saturation map by March 2002.

This performance is illustrated in wells JPB9 and SW13 (Figure 3.20). This figure indicates that skin damage increased dramatically during the second half of 2000. Liquid production also declined from 400 bbl/m and 25 bbl/m to almost no production in wells JPB9 and SW13, respectively. In January of 2002, workovers reversed this decline in productivity and reduced skin from 50 to 20. Examination of Figure 6.10 indicates that this performance can be attributed to the arrival of the flood front and the presence of suspended particles in the flood front that damage the reservoir.

Similarly, the performance of the wells JN9 and JHRS103 (Figure 3.21) has been impacted by the displacement process. Stimulation resulted in an improved performance. But, after only 3 months productivity began to decrease.

As indicated in Figure 3.22 and Figure 3.23, the impact of the displacement in terms of the arrival of flood front has not occurred. These wells have no significant skin damage and are producing significant amounts of liquid. It is expected however, given the performance of wells JDHSR6 and JAF1 (Figure 3.22) and wells VMB8 and VMB22 (Figure 3.23), that with the arrival of the flood front, skin damage will increase and well productivity will decrease.

In the case of wells VMB1 and JM10 (Figure 3.24) and wells JM8 and EM5 (Figure 3.25) the flood front has only begun to impact the performance. This is illustrated in Figures 3.24 and 3.25 where skin damage has increased and productivity decreased.

In summary, the injection of the water from coalmines and gas field brine has significantly affected the productivity of the field. The time dependant variation in the skin damage is estimated from the decline in the productivity of the wells located in the field. The results of these analyses will permit the operators of the field to perform efficiently schedule well workovers and stimulations.

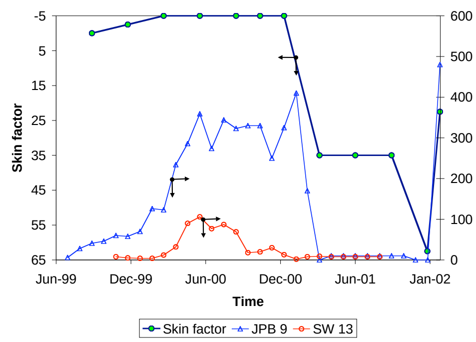


Figure 3.20: Dynamic skin in production wells JPB9 and SW13 of Washington-Taylorstown field

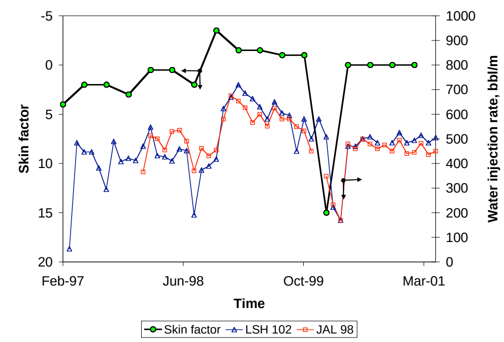


Figure 3.21: Dynamic skin in production wells JN9 and JDHRS103 of Washington-Taylorstown field

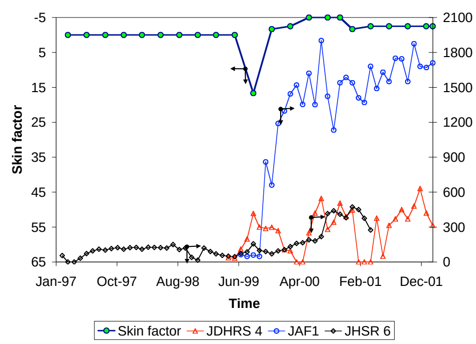


Figure 3.22: Dynamic skin in production wells JDHRS4, JAF1 and JHSR6 of Washington-Taylorstown field

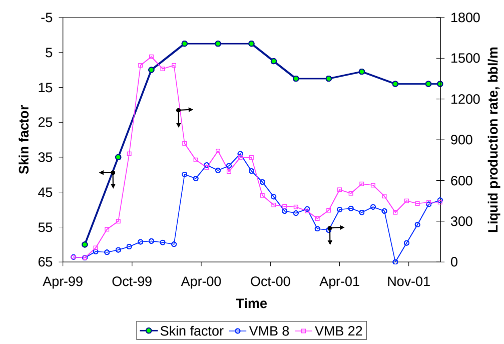


Figure 3.23: Dynamic skin in production wells VMB8 and VMB22 of Washington-Taylorstown field

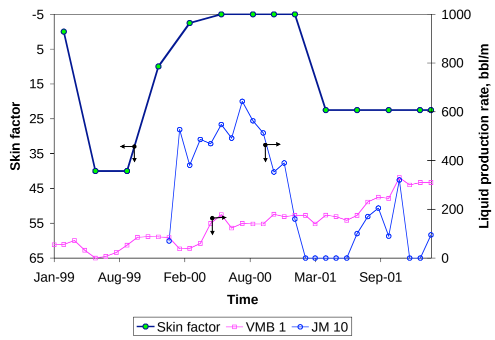


Figure 3.24: Dynamic skin in production wells VMB1 and JM10 of Washington-Taylorstown field

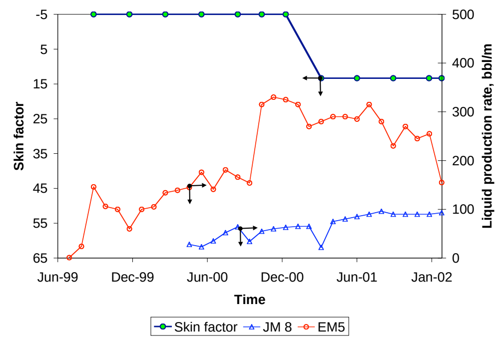


Figure 3.25: Dynamic skin in production wells JM8 and EM5 of Washington-Taylorstown field

4.0 SUMMARY AND CONCLUSION

The objectives of this study were to detail efforts and techniques used to develop representative reservoir models and to provide guidelines for approaching history matching when model development is undertaken using sparse data sets. These objectives were achieved. Using sparse data sets, the reservoir models developed satisfactorily matched the behavior of the reservoirs studied. This suggests that the techniques for characterizing rock and fluid properties were appropriate.

The similarities in the rock and fluid properties for the Taylorstown and the Wileyville reservoirs suggest that data used to characterize and initialize these properties could be extended for use in simulation studies of other reservoirs in the basin. Therefore, this study provides other operators with a tool for analyzing other Gordon reservoirs in the Appalachian basin.

This study shows that the rock properties could be considered uniform throughout the thickness of the reservoirs analyzed. Even though, some log analyses indicated that these reservoirs contain shales forming discontinuities and restrictions to the flow of the different phases, the results obtained suggest that the effect of these shales could be captured by varying the permeability assigned to each block in the models, and that a single layer model is a reasonable approach. These restrictions to the flow suggest that compartmentalization affects the behavior of the reservoir, and may be described in the models using permeability changes in the blocks. It can be concluded that the reservoirs studied may be appropriately described as being heterogeneous single layered.

Given the sparsity of the data, the role of the field staff proved to be crucial in determining the “acceptable” range for adjustment of the reservoir data, and for defining the “confidence” intervals for production data. In addition, the operations staff provided useful insights on the reservoirs. The field staff identified the locations of high water or gas saturations, the location of restrictions to fluid flow in the reservoirs, and reported the operating status of wells that have use for future production or injection. The use of this data improved the “quality” of the history match by incorporating this field knowledge into the process, and thus avoiding a possible numerical solution that does not represent the behavior of the fields.

The systematic approach proposed to complete the history matching proved to be effective in developing an understanding of the behavior of the reservoirs studied. This approach also permitted estimation of the localized damage found in the injection and production wells of the fields.

The results of the study applied to the Taylorstown and the Wileyville fields suggest that the skin damage of all the injection wells increased with time. The formation of emulsions due to the mixture of multiple kinds of injection waters and minerals, the deposition of solids from the injected waters, and the iron precipitate in the borehole due to corrosion of the tubing and casing are the possible causes of the increasing skin damage. Quantification of these effects could not be computed; but were determined inferentially through history matching.

The waterflood operations of the Taylorstown field were evaluated, and predictions of the future behavior of these fields under various operating conditions determined. The following conclusions can be drawn from the reservoir study conducted:

1. The results of the history matching showed that the injection pilot flood exerted an important effect in the southern part of the unit, filling up void spaces and displacing the oil toward the southern portion of the reservoir. The water volumes injected during the injection pilot explain the high fluid levels found in the James Hodgens Sr. 9, and James Hodgens Sr. 10 wells at the beginning of the water injection operations in 1996. It also explained the behavior of J. A. Flack 1 well (JAF 1). This well is located in the southwestern portion of the unit and is the most productive wells in terms of liquid production.
2. The high gas saturation estimated for the northern part of the unit explains the low productivity of the wells, the low oil saturations, and large fill up time for this part of the reservoir.

The objective of the study, which was to analyze the dynamic nature of skin damage, was achieved. The presence of skin is not only due to matrix permeability variations; but also external factors such as mixed fluids injection, suspended particles and particle deposition. In the field case presented in this study, it was not possible to quantify the impact of each element on well performance and the change of skin with time. The overall skin effect however resulted from:

- Particle deposition. The damage caused by particle deposition appears to be irreversible. It can be reduced through stimulation but original reservoir conditions or zero skin cannot be attained.
- The presence of oxygen in reservoir promotes the formation of skin. Chemical reactions take place in the reservoir and results in the formation of emulsion that causes partial blockage.
- With the presence of oxygen, the oxidation of metallic elements is enhanced and migrates to the formation via transport by injected liquids.

Estimates of the skin can be determined from the rate of change in the injection or production flow rates. This information can be used to optimally schedule well workovers. The results of the study suggest that the more homogeneous the reservoir rock, the greater the benefit of well stimulation reducing near wellbore damage.

Recommendations

It is recommended that field monitoring be continued to confirm the results of this study. The continuous tracking of the behavior of the skin with time will provide a better understanding of its effect with time. This needs to be accomplished not only at the field level, but should include laboratory analysis of the fluids produced.

For studies of other fields in the Appalachian basin, it is recommended that the field operations staff and the simulation team work in concert. The role of the field staff proved to be important in determining the “acceptable” range for adjustment of the reservoir data, and to define the “confidence” intervals for the production data that need to be history matched. In addition, the use of the data provided by the field staff improves the “quality” of the history match by incorporating field knowledge into the solution. This avoids a numerical solution of the problem that might not represent the behavior of the fields.

It is recommended that a chemical analysis of the emulsions that are being recovered during the workovers of the production wells be undertaken. This may allow the identification of a chemical agent that could be injected into the reservoir to improve its injectivity and also reduce the time between workovers.

The evaluation of the waterflood operations and the forecasts performed for the Taylorstown field suggests the following strategies to improve the productivity of the reservoir:

1. Recondition the production wells J.A. Flack 2 (JAF 2), J. A. Flack 3 (JAF 3), James Hodgens Sr. 9 (JHSR 9), James Hodgens Sr. 10 (JHSR 10), T. Hilton 5 (TH 5), and J. Crossland 2 (JC 2) to operate by December 2002.
2. Recondition an injection well of the injection pilot by December 2002.
3. If the results of the wells reconditioned in December 2002 are positive, and in good agreement with the forecast, then it is suggested that consideration be given to the reconditioning of production wells J. Flack 4 (JAF 4), and Carson Heirs 1 (CH 1), which are located outside the unit.
4. Recondition Wells James McMannis 6 (JM 6), H. Westfall Etux 14 (HW 14), and Joseph Hutchinson 5 (JH 5) for operation by August 2004.
5. If the oil and water production is according to the forecast, then it is suggested that two wells be drilled and cored to increase knowledge concerning water and gas saturations in the southern portion of the reservoir. These data are required to evaluate the potential of the possible future expansion of the waterflooding operations.

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Waterflooding in Gordon Sandstone Formation – Wileyville Field

during the Period 05/15/2001 to 09/30/2002

By

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ABSTRACT

The Appalachian Region contains hundreds of oil fields that were developed during the late 1800's and/or early 1900's. These fields contain oil reserves that may be recovered using secondary recovery methods such as waterflooding. Technical and economic evaluation of these fields for these capital-intensive operations requires in-depth engineering studies that usually include a field-scale computer model. However, the data needed for building such models are lacking given that modern tools for formation evaluation were not available when these fields were developed (early 1900's).

The objective for this study was to analyze the Wileyville field located in the Wetzel County, West Virginia, for the purpose of improving the performance of an ongoing water flood. To accomplish this objective it was necessary to develop a simulation methodology for a reservoir containing sparse data sets.

This study describes the approach, and protocol employed to characterize and build the computer model of the field in spite of the sparse data sets. The protocol utilizes a systematic approach to complete the history matching, which proved to be effective in understanding the behavior of the reservoir under study. The results obtained provide the operators of the Appalachian basin with a tool to characterize, initialize and perform computer simulation studies of any of the hundreds of reservoirs found in the basin.

From the results obtained, it was concluded that the change in well-bore damage with time in waterflooding operations might result from the types of fluids injected. In the Wileyville field study, it was concluded that the heterogeneous nature of the formation was the principal factor that impacted productivity and injectivity. Moreover, it appears that there is a correlation between production and injection well damage and the physical location of wells within the field.

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1.0 INTRODUCTION

The goal of reservoir engineering and its attendant studies is to maximize oil recovery from the subject reservoir. During the primary production phase, it is the management of the natural energy of the reservoir that maximizes the production. However, continued production at an economic level typically requires implementation of secondary recovery technologies such as waterflooding. These projects tend to be capital-intensive and as such, demand use of modern reservoir techniques such as numerical simulation for their design and optimization.

These simulation studies demand a significant amount of reservoir specific data. This data include production and pressure history and wireline logs. In the case of fields such as the Wileyville Field in West Virginia, the field was developed for primary production before many of the commonly used technologies were developed. These technologies include wireline logs and downhole pressure measuring devices. Moreover, much of the individual well production data in terms of daily and total production, were not available. To accomplish the stated objective of this study which was to evaluate the ongoing waterflooding operations at the Wileyville field, it was necessary to develop a protocol for use when dealing with the simulation of reservoirs with sparse or incomplete data sets.

It is postulated that this protocol will be of a value to other operators in the Appalachian basin who may consider the implementation of enhanced recovery in these first generation oil fields that were developed for primary production during the late eighteenth and early twentieth centuries. Moreover, the model itself will be of a specific value to the operator of the Wileyville field who may consider additional development in this field or to optimize its operations.

1.1 Background

To accomplish this study, data from ongoing field operations were used. The data were from the Gordon sandstone formation found in the Appalachian Basin. The Gordon sand belongs to the Venango group of the Upper Devonian age and received its name in 1885 when discovered by drilling operations on the Gordon farm in Washington, Pennsylvania.

Among the most predominant properties that characterize the sandstone at this location are: 1) the depth at which it is found (between 1500-ft and 3000-ft); 2) the permeability ranges (from 90-md to 200-md); and 3) the average porosity value of approximately 20 percent. Values out of these ranges could generally be found in any of the wells penetrating this formation (Harper, 1987 and Lytle, 1950).

The area of interest for the study is located in Wetzel County, northwest West Virginia, where the fields of Wileyville is located. This field produces from the Gordon sand formation and is one of the many fields found in Pennsylvania, Ohio and West Virginia that have the potential for waterflooding.

As previously stated, fields penetrating the Gordon formation were discovered in the late 1800s and at the beginning of the 20th century. During the early development stage of the fields, primary production was the principal mechanism for oil production. However, this primary production ended by the middle of the century because the reservoir drive mechanism was depleted. It was estimated that approximately 10 to 25 percent of the original oil in place had been recovered. Therefore, alternative recovery methods have been studied to keep these stripper well reservoirs economically profitable (Cardwell, 1978). Stimulation and secondary oil recovery projects were applied to different areas of the reservoir, with varying degrees of success. Gas injection and waterflooding were the most widely secondary recovery methods even though air injection has also been practiced.

It is suggested in this study that waterflooding of the Wileyville is feasible from a technical perspective. Moreover, the study suggests that a computer model of a field with sparse data sets can be developed. The prerequisite is a close partnership between the modeling team and the field operators where an active an ongoing exchange of data takes place. Performance of the field can then be compared between that experienced in the field and that predicted by the computer. Variances can then be used to adjust the model and improve its performance.

1.2 PROBLEM STATEMENT

The skin factor is the representation of a damaged or stimulated wellbore. Skin damage is present from the time a well is drilled, and then completed. It is present during the entire life of the well whether the well is in operation for production or injection purposes.

Although skin effect has been the subject of numerous investigations, e.g. Fetkovich (1973), Tippie et al. (1974), Blacker (1982) and Hansen et al. (2002), the dynamic nature of the phenomenon has not been thoroughly investigated. Dynamic skin is influenced by a variety of parameters that cause the productivity index of the well to vary. It is well understood that operating conditions are not always the same. For example, the reservoir conditions may change with oil production and fluid injection rates may vary with well stimulation and/or mobilization of suspended particles by the injected fluid. These changes and their impact on the wellbore (skin damage) must be considered in conducting a reservoir analysis.

Analysis of the impact of dynamic skin on production and injection rates is the focus of this investigation. To achieve this objective, the behavior of the Wileyville field is analyzed. This field is currently undergoing waterflooding,. The results of this analysis are used to provide insight concerning the dynamic skin.

The representation of the dynamic skin effect is made with numerical reservoir simulation. A commercial black oil model simulator (Eclipse 100) is used as the tool to pursue the principal objective of this study. The methodology used to develop the model is the history matching process, which when coupled with current field operating reports confirm the veracity of this approach.

2.0.CHARACTERIZATION OF THE GORDON SANDSTONE

Reservoir characterization includes estimating and formatting of the reservoir data needed to build a model in a form that can be used by the simulator. Reservoir characterization includes the selection of a grid and associated data for use in the model. Data acquisition is an essential part of the model characterization and initialization, and the quantity and quality of the data used to initialize the model play a relevant role in the effectiveness and reliability of the history matching.

Parish et al. (1993) mentioned that two important tasks of the engineer conducting a history matching are: make a careful assessment of the observed data to be matched and making an assessment of the basic reservoir description. The description of a reservoir involves the estimation of its rock and fluid properties. There are many techniques to estimate the value of different properties, such as permeability or porosity, in different locations of a reservoir. Many of these techniques interpolate values from the analysis of the data obtained from a few wells drilled in certain strategic locations of the field.

In this study, four steps were followed to develop an initial description of the reservoir:

1. A description of the area extent and reservoir structure is developed. To this description, a grid is applied.
2. A model of the fluids is developed. Where specific data describing the intrinsic properties are not available, suitable correlations available from the literature are used.
3. Rock properties such as porosity, initial phase saturations, relative permeability, absolute permeability and capillary pressure are estimated at locations throughout the reservoir.
4. Data based on the historical development of the field are then used to initialize the field model.

In this study, most of the properties of the fluids involved are not known; therefore, there was the need to estimate the fluid properties by means of assumptions and correlations. Also, some of the rock properties of the field are not known, such as absolute permeability, relative permeability, and fluid saturations. In this case, different approaches are proposed to estimate the data needed to initialize and characterize the Wileyville reservoir. This is done in order to complete the representation of the model and guarantee the consistency of all the assumptions made.

Initialization of the reservoir properties depends upon an appropriate description of the field's history to allow an efficient history matching process and the best possible representation of the actual behavior of the reservoir. The question that must be addressed by the modeler is the "uniqueness" question and the reasonableness of any predictions made using the model. As previously indicated, data sets from a field currently under development (Wileyville field) were used to sustain the proposed approach.

2.1 Characterization of the Wileyville field

2.1.1 Field Structure and grid description

The Wileyville field, a shallow inland oilfield located in Wetzel County, West Virginia is approximately 100 miles SSW of Pittsburgh, Pennsylvania. This field produces from the Upper Devonian Gordon Sandstone. This sandstone is blanket sand and can be described as a spoon-shaped syncline.

The operator of the field, East Resources Co, provided a structure map and a net pay thickness isopach map. These maps were used to identify the external boundaries of the field and the thickness of each region of the reservoir. These maps were developed using wireline log readings obtained from different wells in the field. The Gordon sandstone at Wileyville is located at an approximate depth of 3000-ft. It has an average net pay thickness of 12 feet. The reservoir has an estimated area of 2435 acres. These maps provided the basis for constructing the grid of the model.

The model development involved the creation of a non uniform, two-dimensional grid. The decision to develop a two-dimensional grid was based on the assumption that the properties of the sand are uniform throughout the thickness of the sand. This assumption is supported by the results of an analysis performed by Core laboratories Inc, on a core extracted from the L. S. Hoyt 100 well of the Wileyville field.

The model contains 498 active blocks, 23 production wells and 18 water injection wells. Figure 2-1 illustrates the location of the wells, and Table 2-1 lists the wells, and their location in the grid system. Tables 2-2 and 2-3 list the width and the height of each block respectively, according to its coordinates in the numerical grid..

The Wileyville field is a closed reservoir, therefore the external boundary conditions of the model are no flow boundaries. The internal boundary conditions are defined as follows: the production wells are modeled by assuming a constant bottom hole pressure of 95 psig, and the water injection wells maintain a constant bottom hole pressure equivalent to the wellhead pressure plus the pressure exerted by the hydrostatic column of water in the well.

2.1.2 Fluid properties

Due to the lack of information about the reservoir fluid properties, several correlations and assumptions were used to develop a thermodynamic and physical black-oil model capable of simulating the behavior of the reservoir fluids under the various operating conditions. Little information is available to estimate the physical properties of the reservoir fluids. The properties known include an oil API gravity of 40° (Lytle, 1950), and bubble point pressure of 780 psia (Pennzoil, 1985).

The characteristics of the gas present in the Wileyville field are known. The specific gravity of this gas was determined to be 0.9 using a gas chromatographic analysis. Gas Analysis Systems, Inc. performed this analysis, during June 2001. The water specific gravity was assumed constant and equal to 1.0, and the gas phase was assumed immiscible in the water phase. Also, it was assumed that the temperature of the reservoir remains constant at all times.

Given the sparse information known about the properties of the fluids present in this field, a PVT model was developed using published correlations. The PVT model developed is a black-oil model, with the capability to simulate dissolved gas in the oil phase.

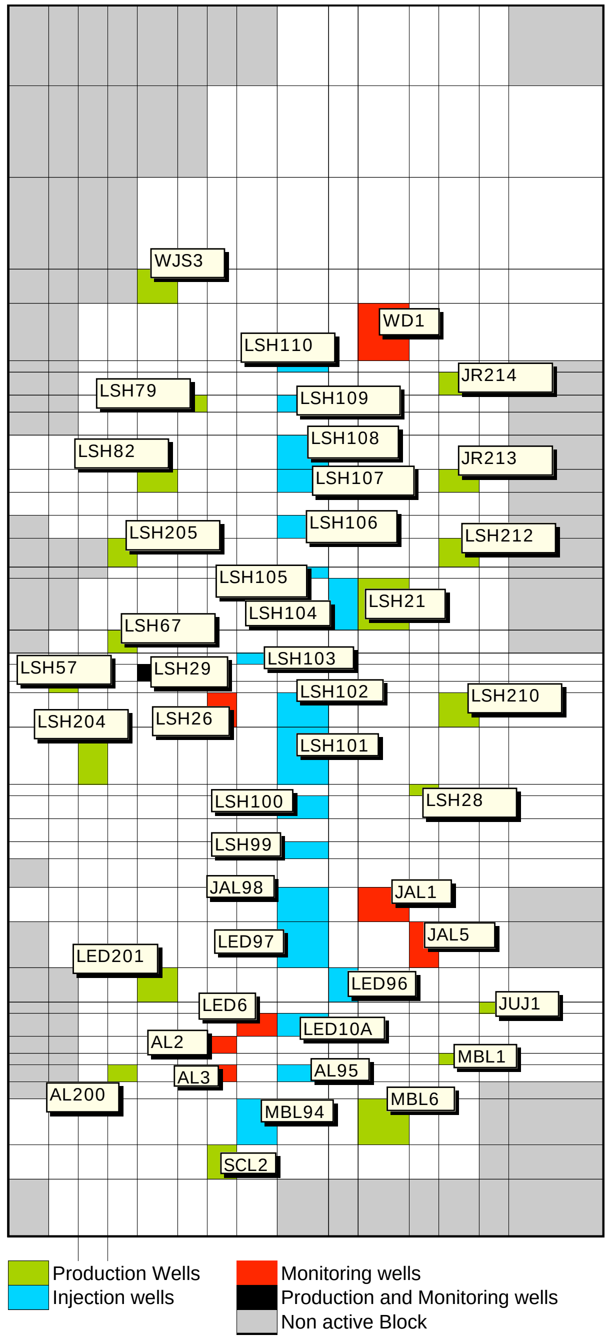

Figure 2-1. Location of the wells in the grid of the Wileyville field

Farm	ID	Code	#	Locat.	
				X	Y
INJECTION WELLS					
L.S. Hoyt	1711	LSH	110	9	6
L.S. Hoyt	1717	LSH	109	9	8
L.S. Hoyt	1716	LSH	108	9	10
L.S. Hoyt	1710	LSH	107	9	11
L.S. Hoyt	1709	LSH	106	9	13
L.S. Hoyt	1708	LSH	105	9	15
L.S. Hoyt	1721	LSH	104	10	16
L.S. Hoyt	1707	LSH	103	8	18
L.S. Hoyt	1706	LSH	102	9	21
L.S. Hoyt	1705	LSH	101	9	22
L.S. Hoyt	1685	LSH	100	9	24
L.S. Hoyt	1704	LSH	99	9	26
Jacob A. Lantz	1720	JAL	98	9	28
Louise E. Dulaney	1719	LED	97	9	29
Louise E. Dulaney	1718	LED	96	10	30
Louise E. Dulaney	1749	LED	10A	9	32
Ara Long	1743	AL	95	9	35
Mary B. Long	1742	MBL	94	8	37
PRODUCTION WELLS					
W.J. Santee	1457	WJS	3	5	4
L.S. Hoyt	1532	LSH	79	6	8
L.S. Hoyt	1003	LSH	82	5	11
L.S. Hoyt	1773	LSH	205	4	14
L.S. Hoyt	O994	LSH	67	4	17
L.S. Hoyt	1218	LSH	29	5	19
L.S. Hoyt	O992	LSH	57	2	20
L.S. Hoyt	1744	LSH	204	3	22
Jennetta Chamberlain	1745	JC	203	4	25
Louise E. Dulaney	1748	LED	202	4	28
Louise E. Dulaney	1797	LED	201	5	30
Ara Long	1777	AL	200	4	35
Sarah C. Long	1027	SCL	2	7	38
Mary B. Long	1026	MBL	6	11	37
Mary B. Long	1022	MBL	1	13	34
J. U. Jaliff	1007	JUJ	1	14	31
L.S. Hoyt	1217	LSH	28	12	23
L.S. Hoyt	1776	LSH	210	13	21
L.S. Hoyt	SN	LSH	21	11	16
L.S. Hoyt	1774	LSH	212	13	14
Jonh Rush	1775	JR	213	13	11
Jonh Rush	1772	JR	214	13	7
MONITORING WELLS					
Ara Long	1020	AL	3	7	35
Ara Long	1019	AL	2	7	33
Louise E. Dulaney	963	LED	6	8	32
Jacob A. Lantz	1013	JAL	5	12	29
Jacob A. Lantz	1010	JAL	1	11	28
L.S. Hoyt	1216	LSH	26	7	21
L.S. Hoyt	1218	LSH	29	5	19
Weslye Dulaney	S/N	WD	1	11	5

Table 2-1. Names and location of the wells (Wileyville field)

X Coord.	DX [ft]
1	375
2	250
3	250
4	250
5	375
6	250
7	250
8	375
9	500
10	250
11	500
12	250
13	375
14	250
15	1000

Table 2-2. Width of each block of the grid system (DX – Wileyville field)

Y Coord.	DY [ft]
1	1750
2	2000
3	2000
4	750
5	1250
6	250
7	500
8	375
9	500
10	750
11	500
12	500
13	500
14	625
15	250
16	1125
17	500
18	250
19	375
20	250
21	750
22	1250
23	250
24	500
25	500
26	375
27	625
28	750
29	1000
30	750
31	250
32	500
33	375
34	250
35	375
36	375
37	1000
38	750
39	1250

Table 2-3. Height of each block of the grid system (DY – Wileyville field)

The PVT model requires the determination of certain properties at different pressure conditions. For the oil phase, these properties were: solution gas-oil ratio (R_s), oil formation volume factor (B_o), oil compressibility (c_o), and oil viscosity (μ_o).

The solution gas-oil ratio at different pressures was estimated using a correlation developed by Glaso in 1980. This correlation is shown below:

$$R_s = \gamma_g \left[\frac{API^{0.989}}{T^{0.172}} 10^{Y} \right]^{1.22549}$$

where:

R_s = solution gas-oil ratio, SCF/STBO

T = temperature,°F

API = oil API gravity

γ_g = specific gravity of the gas at standard conditions

and Y is defined as follows:

$$Y = \frac{1.7447 - \sqrt{5.1797 - 1.2087 * \log(p)}}{0.6044}$$

where:

p = pressure, psia.

The oil formation volume factor was determined using the following correlation developed by Standing:

$$B_o = 0.972 + 0.000147 F^{1.175}$$

where:

B_o = oil formation volume factor, bbl/STBO

The F factor is determined using the following equation:

$$F = R_s\sqrt{\frac{\gamma_g}{\gamma_o}} + 1.25T$$

where:

R_s = solution gas-oil ratio, SCF/STBO

T = temperature,°F

γ_g = specific gravity of the gas at standard conditions

γ_o = specific gravity of the oil at standard conditions

The oil compressibility was determined by means of the Vazquez and Beggs correlation shown below:

$$c_o = \frac{-1433 + 5R_s + 17.2T - 1180\gamma_{gc} + 12.61API}{10^5\,p}$$

where:

c_o = oil compressibility, psi-1

R_s = solution gas-oil ratio, SCF/STBO

T = temperature,°F

API = oil API gravity

γ_g = specific gravity of the gas at standard conditions

γ_o = specific gravity of the oil at standard conditions

p = pressure, psia

Finally, the oil viscosity was estimated using the Beggs & Robinson correlation:

The viscosity of the live oil is determined by:

$$\mu_{ol} = \left(10.715\left(R_s + 100\right)^{-0.515}\right)\mu_{od}^{\,b}$$

where:

μ_{ol} = viscosity of the live oil, cp

μ_{od} = viscosity of the dead oil, cp

R_s = solution gas-oil ratio, SCF/STBO

The b factor is calculated by the following equation:

$$b = 5.44\left(R_s + 150\right)^{-0.338}$$

The viscosity of the dead oil is estimated using the correlation shown below:

$$\mu_{od} = 10^{x} - 1$$

where x is calculated as:

$$x = \frac{10^{\left(3.0324 - 0.02023 API\right)}}{T^{1.163}}$$

For the water phase the only properties estimated at different pressures were the water formation volume factor (B_w), the water compressibility (C_w), and the water viscosity (μ_w). The water formation volume factor was estimated by means of the Gould correlation:

$$B_w = 1.0 + 1.2x10^{-4}\left(T - 60\right) + 1.0x10^{-6}\left(T - 60\right)^2 - 3.33x10^{-6}\, p$$

where:

B_w = Water formation volume factor, bbl/STBW

T = temperature,°F

p = pressure, psia

The water compressibility was calculated using the Meehan correlation for gas free water.

$$c_w = 10^{-6}\left[A + BT + CT^2\right]$$

where:

c_w = water compressibility, psi-1

T = temperature,°F

and the variables A, B, and C are defined as:

$$A = 3.8546 - 0.000134 p$$
$$B = -0.01052 + 4.77x10^{-7} p$$
$$C = 3.9267x10^{-5} - 8.8x10^{-10} p$$

where:

p = pressure, psia

The water viscosity is estimated by means of the Beggs & Brill correlation, shown below:

$$\mu_w = \exp\left(1.003 - 1.479x10^{-2} T + 1.982x10^{-5} T^2\right)$$

where:

μ_w = water viscosity, cp

T = temperature,°F

For the gas phase, there was the need to determine the gas compressibility (B_g), and the gas viscosity (μ_g) at various pressures. The formation volume factor was determined using the real gas equation of state, where:

$$B_g = 0.0283 \frac{ZT}{p}$$

where:

B_g = gas formation volume factor, Cf/SCF

T = temperature,°R

p = pressure, psia

z = gas compressibility factor

To calculate the viscosity of the gases the Lee et al correlation (1966) was employed. This correlation is shown below:

$$\mu_g = K \times 10^{-4} \exp\left[X\left(0.0433\gamma_g \frac{p}{Z(T+460)}\right)^{Y}\right]$$

where:

μ_g = gas viscosity, cp

T = temperature,°R

p = pressure, psia

z = gas compressibility factor

The variables K, X and Y are defined as follows:

$$K = \frac{(9.4 + 0.02M_a)(T+460)^{1.5}}{209 + 19M_a + (T+460)}$$

$$X = 3.5 + \frac{986}{(T+460)} + 0.01M_a$$

$$y = 2.4 - 0.2X$$

where:

M_d = Molecular weight of the gas.

Even though the fluid properties available to build the model were sparse, the correlations and assumptions employed allowed building a complete PVT model that is able to simulate the behavior of the three phases involved in the reservoir.

2.1.3 Rock properties

The formation studied is the Upper Devonian Gordon Sandstone. The rock properties of interest to perform this simulation study are: porosity, absolute permeability, relative permeability, initial saturations, and capillary pressure.

The porosity in different locations of the field was determined using pore-feet maps provided by the operator of the field. This pore-feet map allowed calculating the porosity in all the grid blocks of the numerical model.

There was no information available for the saturations distribution in the field. However, the operator indicated that it was reasonable to initialize the model assuming that the water saturation throughout the entire reservoir is 25% and the gas saturation is 25%. This estimate of saturations provided by the operator is based on their experience operating wells throughout the basin.

There was one core available for use in the Wileyville study: The analysis was performed by Core Laboratories, Inc. on a core obtained from the L. S. Hoyt 100 well. The results of the analysis included relative permeability curves that were used in creating characteristic relative permeability curves for the simulation (Figure 2-2). Additionally, this core was also used to provide information for estimating the value of absolute permeability. The value of average absolute permeability of this core is 50-md.

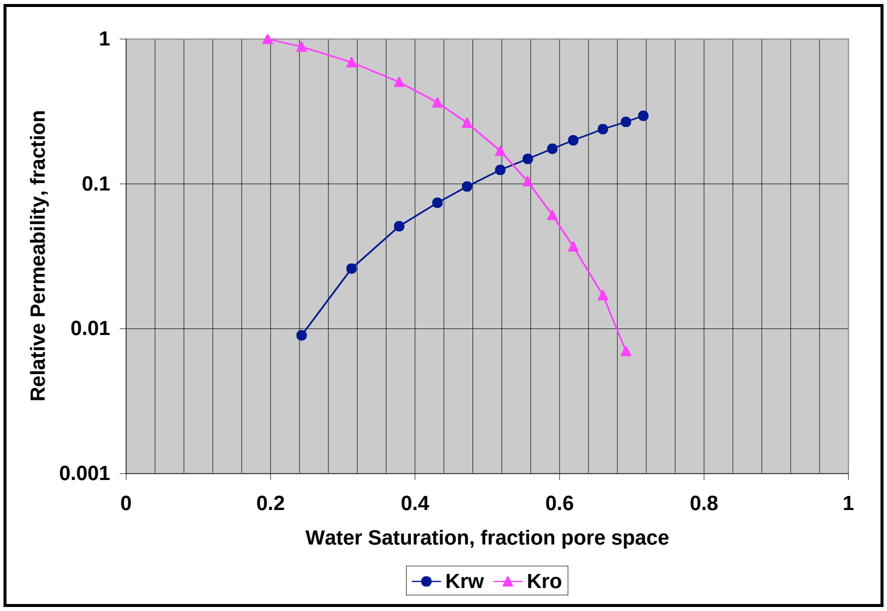

Figure 2-2. Kr vs. Sw. (L. S. Hoyt 100 Well, Wileyville Field)

2.1.4 Historical development of the waterflooding

Water injection at Wileyville began in February 1997. At this time there were 41 active wells. Of these wells, 18 are injection wells that are arranged in a line drive pattern. The remaining 23 production wells are located east and west of the injection wells toward the external boundaries of the reservoir. Since water injection started, there has been injected 5,300,000 barrels of water, and the field started to show a significant response in terms of formation water and/or oil production in May of 2002.

3.0 RESULTS & DISCUSSION

3.1 History matching results

After a several iterations during which the parameters in the simulation model were adjusted, a satisfactory history match was achieved. The results obtained indicated an acceptable model behavior, which mimics the operation of the field since waterflooding was initiated in February 1997. The following sections contain a discussion of the results of the history matching.

3.1.1 Discussion of the results of the Injection match

The results of the injection match were compared using a two-step process. In the first step, the trends of the actual and the simulated curves were compared qualitatively to ensure that the trends of both curves are similar. Second, the values of the actual and the simulated cumulative water volumes injected were computed and compared, and indicated a small difference in the values injected (less than 15%).

The results show that the simulated water injection behavior is qualitatively close to the actual injection trend. Consequently, it can be seen that the simulated cumulative water injection of the field scale match is in good agreement with the actual water injected in the reservoir (Figure 3-1).

The cumulative water injected for the actual operation and for the simulation was computed and compared to verify that the actual and simulated water injected volumes were similar. In this case, the acceptance criteria established that the error should not be higher than 10 %. This value is based on the accuracy of the orifice meters used to measure the water injection rates for each well.

Figure 3-2 compares the actual and the simulated cumulative water volumes injected for each well, while Figure 3-3 shows the error or relative deviation in the cumulative water injected for each well. This figure shows that 15 out of 18 wells are within an error margin of 10%. This error is considered to be acceptable for this study, given the accuracy of the instruments used to measure the injection water rates for each well.

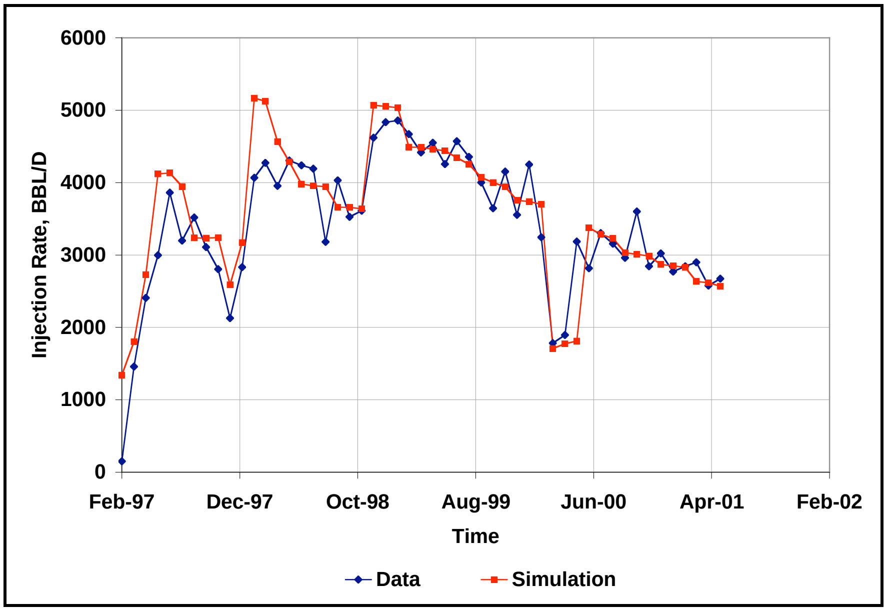

Figure 3-1. Field water injection rate vs. time. Field data vs. simulation results

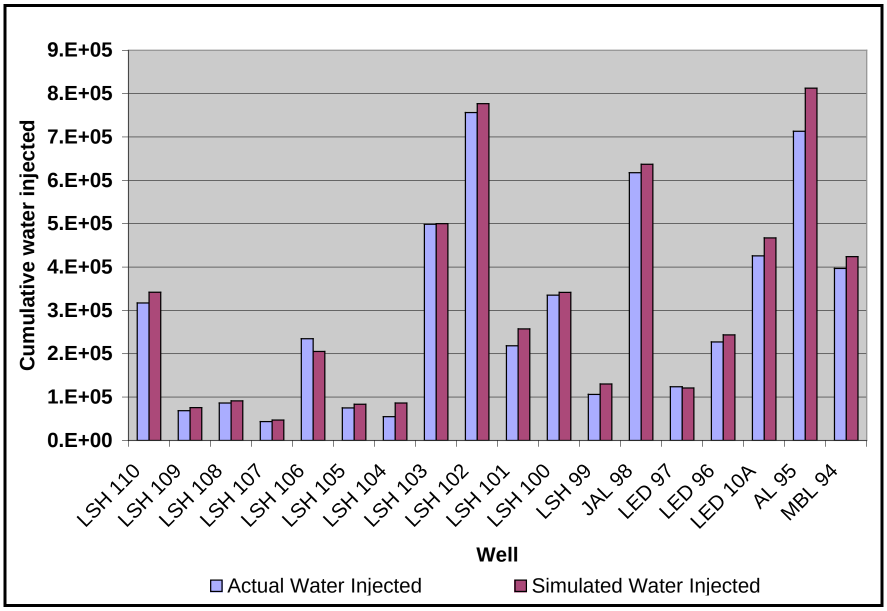

Figure 3-2. Cumulative water injected. Field data vs. simulation results

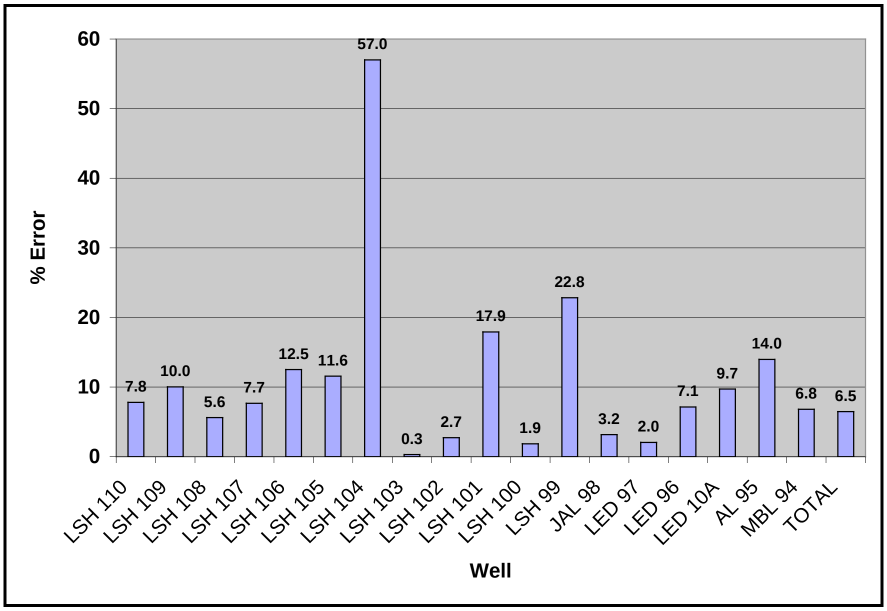

Figure 3-3. Error in cumulative water injection

Only three wells show an error greater than 10%. These wells are L.S. Hoyt 104 (LSH 104), L.S. Hoyt 99 (LSH 99), and L.S. Hoyt 101. Even though the error is greater than the established "acceptable" value for this study, the difference between the actual and the simulated water volume injected for each well is small compared to the water volume injected in the field (about 4%). Consequently, this error is not considered to be significant and its impact on field behavior is minimum.

Finally, it is important to note that the trend of the water injection curves matches qualitatively the behavior for all the injection wells. The deviation in the water volume computed for each well is "acceptable" for the above-explained reasons, and the error in the total water injection of the field is within 7%. Based on these observations, it can be concluded that the water injection match is acceptable.

3.1.2 Discussion of the results of the pressure match

Table 3-1 shows that all the pressures calculated by the model match the pressures obtained from the field, within an error margin of 16%. This error is acceptable given the resolution of the instruments used to read the fluid levels in the wells.

The only well where the error between the actual pressure obtained from the field, and the pressure calculated by the simulator is greater than 20% is the well J.A. Lantz 1 (JAL 1). Even though the error is greater than 20%, the difference between the pressures obtained from the field and the pressure calculated by the simulator for (JAL 1) well is not significant (41 psi). Given the resolution of the instruments used to measure the fluid levels in the wells, it can be concluded that the results of the pressure match are acceptable.

WELL	LOCATION	REAL	SIMULATED	DIFF	ERROR
WD1	(11,5)	476	399	77	16%
LSH29	(5,19)	778	795	-17	2%
LSH26	(7,21)	766	848	-82	11%
JAL1	(11,28)	150	191	-41	28%
JAL5	(12,29)	138	119	19	14%
LED6	(8,32)	693	726	-33	5%
AL2	(7,33)	232	270	-38	16%
AL3	(7,35)	1028	1114	-86	8%

Table 3-1. Pressures measured in the field vs. pressures calculated by simulation

3.1.3 Discussion of the results of the production match

Figure 3-4 compares the actual and simulated production of oil and water for the field. The results show a good qualitative match, since the trends of the actual and the simulated curves for each phase are in good agreement.

Figure 3-5 compares the actual and simulated oil production for each well in the field, while the water data shown in Figure 3-6.

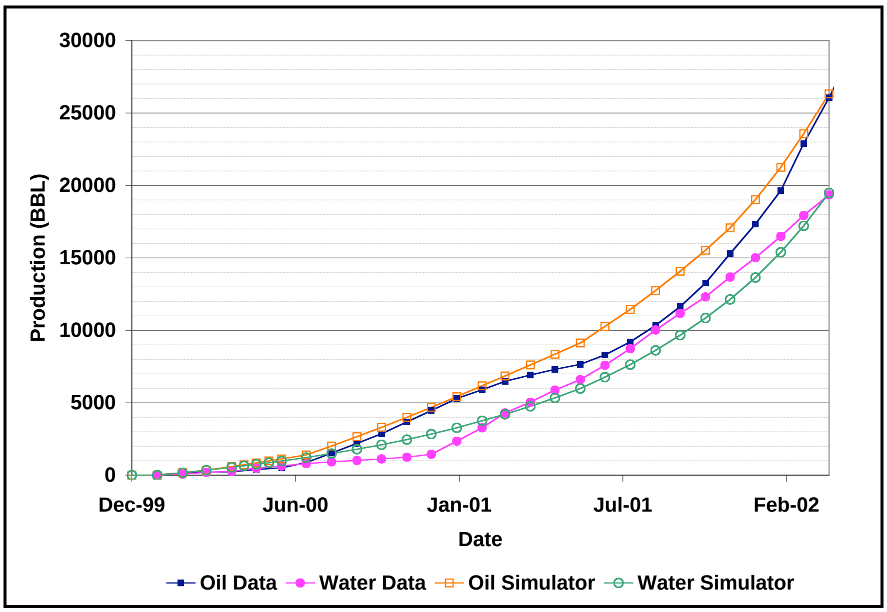

Figure 3-4. Field oil and water production vs. time. Field data vs. simulation results

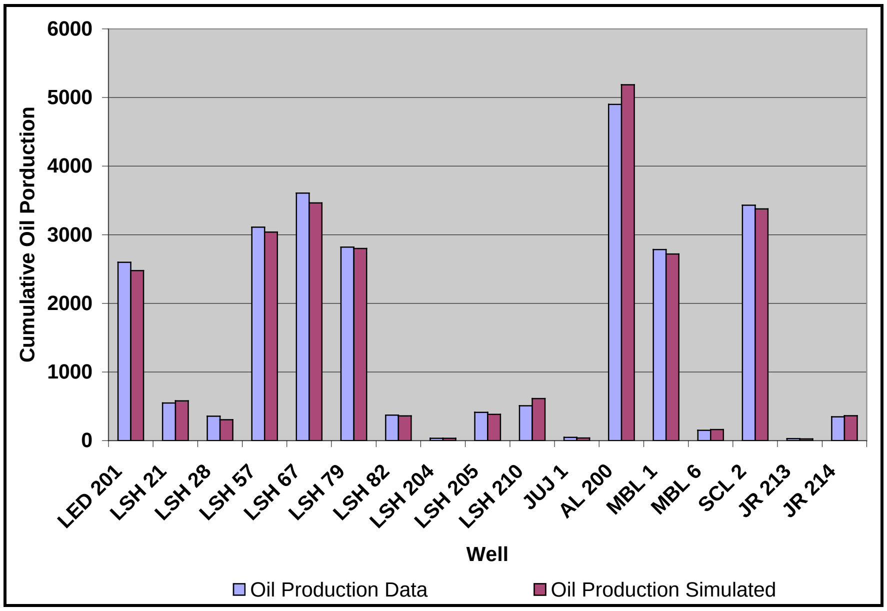

Figure 3-5. Comparison of cumulative oil production per well (February 2002)

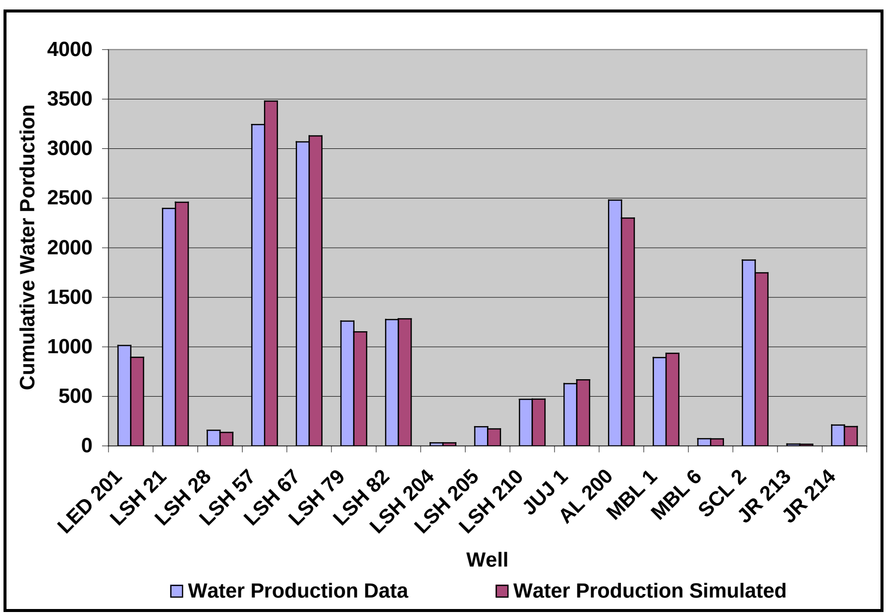

Figure 3-6. Comparison of cumulative water production per well (February 2002)

The results confirmed that the actual oil and water production of each well shows a behavior that closely approximates the simulation results. In addition, Figures 3-5 and 3-6 confirm that the simulated oil and water productions are similar to the actual productions for each well.

Figure 3-7 illustrates the deviation in the cumulative and total oil production for each well. The results show that deviation is less than 10% for 13 of the 17 wells, while the remaining wells had errors ranging from 14 to 21 %. Even though the oil production of those wells is higher than 10%, it is still acceptable since their production is small when compared with the average-well production of the field.

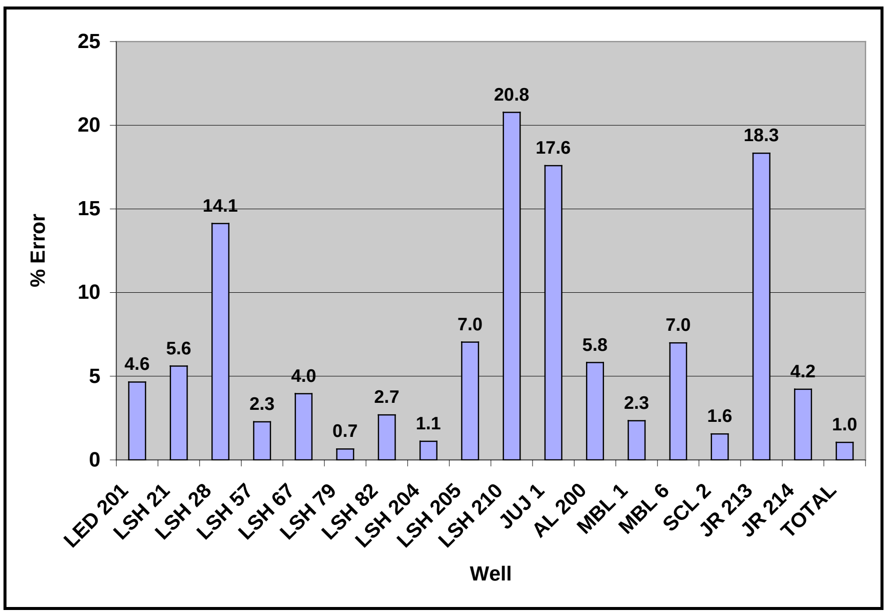

Figure 3-7. Error of the cumulative oil production per well

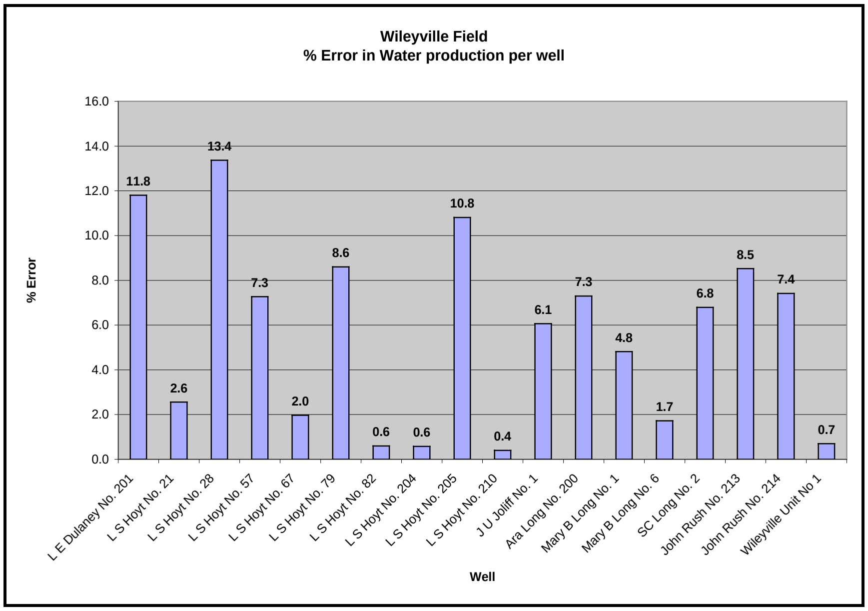

Figure 3-8. Deviation of the cumulative oil production per well

Figure 3-8 shows that the error in the water production is less than 10% for most of the wells, which makes the water production match acceptable. Figures 3-7 and 3-8 verify that the simulation represents a close approximation of the total amounts of oil and water actually produced by the field. The field scale production predicted by the simulator for each phase is within 5%. Given that the injection, pressure and production reached a satisfactory match, it can be concluded that a satisfactory history match was achieved.

3.1.4 Estimation of the unknown properties

Figure 3-9 highlights the regions where the permeability and porosity are expected to be lower than those assumed for the field (absolute permeabilities <10 md and porosities < 10%). The regions highlighted involve several wells that exhibit poor injectivity or productivity. These regions indicate that the reservoir is split into two different areas. A relatively small channel of higher permeability and porosity, as shown in Figure 3-9, apparently permits communication between the two regions of the reservoir.

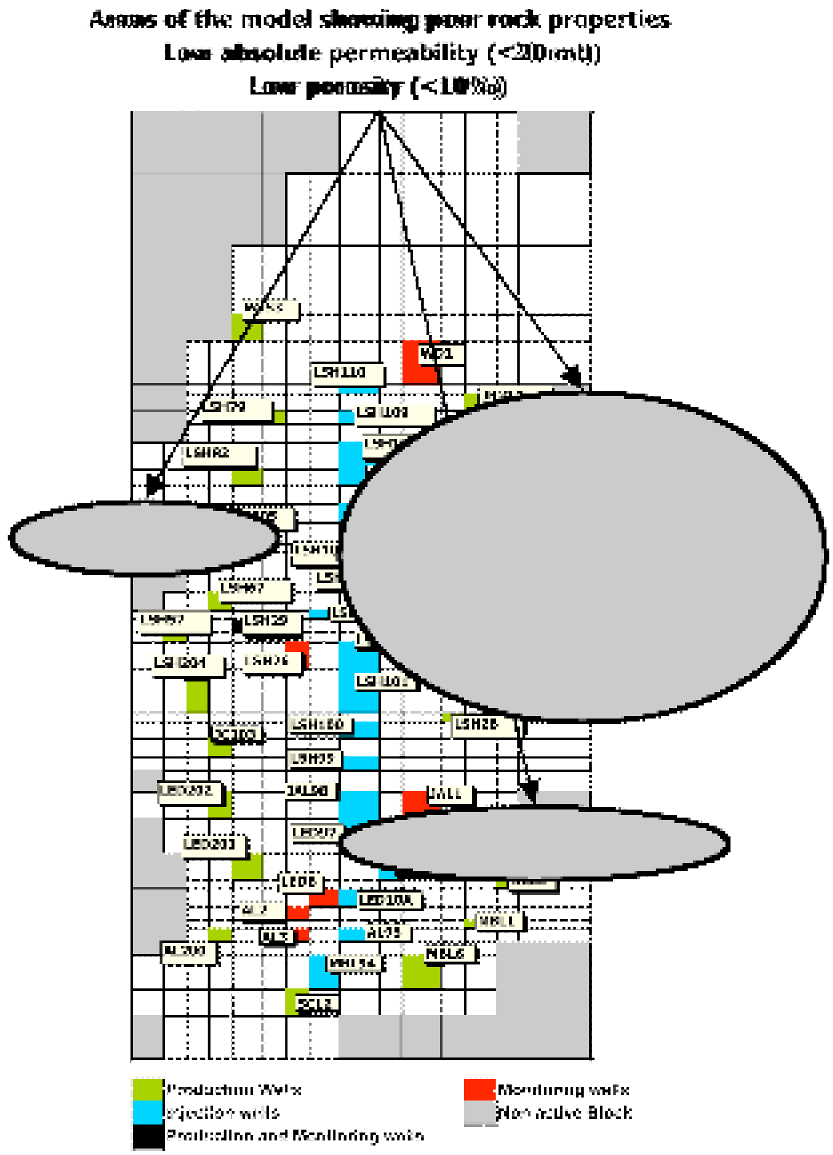

Figure 3-9. Location of the areas of low permeability and porosity in the model

Currently the most prolific wells of the waterflood are the L. S. Hoyt 67 (LSH 67) and L.S. Hoyt 57 (LSH 57) wells. These wells are located in advantageous positions. Figure 3-9 shows that the water injected from wells LSH 101, LSH 102 and LSH 103 impacts wells LSH 57 and LSH 67 and increases their pressures and oil production.

The location of these areas of low permeability and porosity help to explain the low injectivity found in wells L.S. Hoy 107 (LSH 107), L.S. Hoy 106 (LSH 106), L.S. Hoy 105 (LSH 105), L.S. Hoy 104, and L.E. Dulaney 97 (LED 97). It is recommended that additional wells be drilled and cored in these areas to verify the estimated values, and to use the information determined to update the model.

3.2 Wileyville field

For the Wileyville field, the waterflooding project for this field started in early 1997, when the injection line drive pattern was established. Almost three years after water injection began during December 1999, production was realized.

The main concern in the Wileyville field case is the distribution of properties throughout the field. The properties that affected crude oil production and the performance on the secondary recovery process are the porosity (Figure 3-10), permeability (Figure 3-11) and the thickness (Figure 3-12) of the reservoir.

The distribution of the properties on a field scale suggests that a discontinuity is present. It has been suggested that this discontinuity takes the form of a compartment. In terms of the modeling, a sudden change in rock properties was noted in the north-south direction.

Moreover, it was noted that an area of low transmissibility existed in the central portion of the field. The presence of this area will impact the development and performance of the secondary recovery operations. Moreover, this area of low permeability and porosity separates the northern and southern portions of the field.

The rock properties of the northern area are more uneven in terms of permeability and porosity when compared to those of the southern area. As a consequence, water displacement and frontal movement and production will be higher in the southern portion of the reservoir.

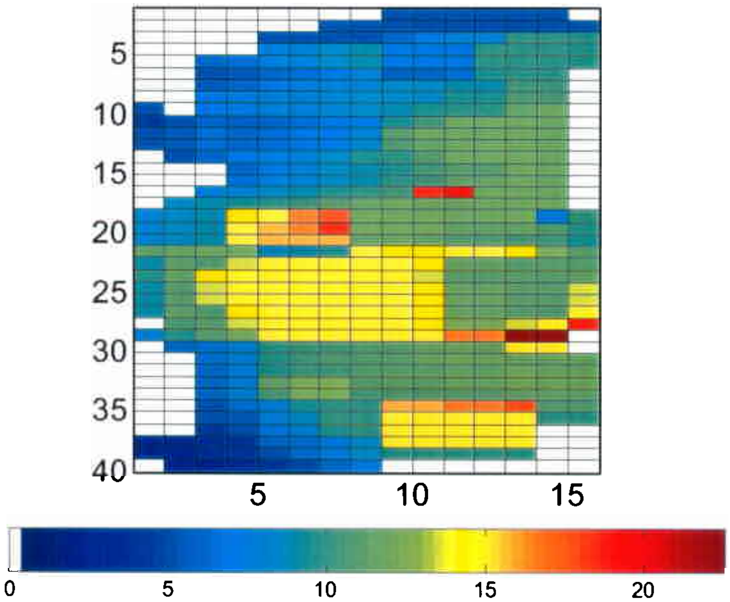

Figure 3-10 Wileyville field, thickness map.

3.2.1 Wileyville field case, injection analysis

The performance of Wileyville in terms of injectivity versus time suggests that there were injectivity problems. During the first two years of injection, the injectivity increased from approximately 100 bbl/d to 4.9 Mbbl/d. After this increase, the injectivity began to decrease reaching the current value of 2.7 Mbbl/d. All injection wells exhibited increasing skin damage during injection. The increase in skin appears to be related to the distribution of properties in this field (porosity and permeability). It also appears that historical operations played a role in the pattern developed by the skin over time.

The injection wells exhibited a trend of increasing skin damage with time after recovery from damage caused by drilling and completion operations. The initial damage lasted for about 3 months, and then an increase in the damage started. Workovers of the injection wells to reduce the damage in the near wellbore region were performed with varying degrees of success. The difference in the results of stimulation is again based on the properties present in the well. Additionally, the proximity of the wells also impacts their post stimulation performance given the fact that the reservoir properties are similar.

The injection wells of the northern portion of the field exhibit a lower injection rate when compared to those in the southern portion of the field. As previously stated, the reservoir quality of southern portion of the field is of a better quality in terms of its porosity and permeability characteristics than the northern one. Therefore, injection wells in this area possess higher injectivity rates and historically 83 % of the total water injection was realized in this area.

For the Wileyville field study, the numbers of regions containing injection wells are seven. All 18-injection wells are accounted for in these regions. Figures 3-13 to 3-19 contain the plots of skin versus time for injection wells. Figure 3-20 contains the history of wells LSH110, LSH109, LSH108 and LSH107. These wells that are located in the northern part of the field have exhibited a continuous increase in skin. This is in spite of stimulation a year into injection. In the case of wells LSH110, LSH109, LSH108 and LSH107, the location of these wells in the poorer quality reservoir rock found in the central portion of the unit is considered to be the principal reason. In the case of LSH106 (Figure 3-14), this well is located to the south separation area between the north and south portion of the field, appears to have formation qualities similar to the central part of the reservoir.

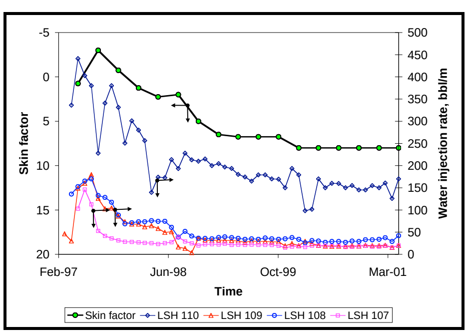

Figure 3-11: Dynamic skin in injection wells LSH110, LSH109, LSH 108 and LSH 107 of the Wileyville field.

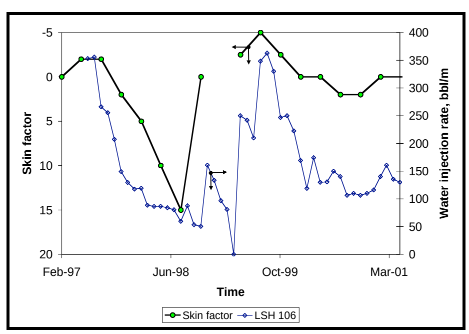

Figure 3-12: Dynamic skin in injection well LSH106 of Wileyville field.

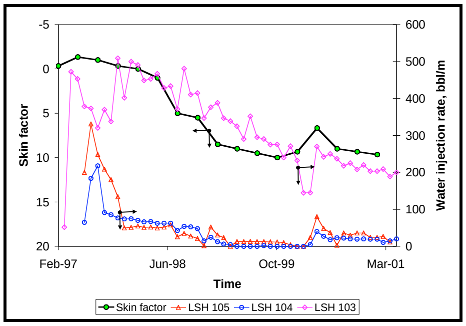

Figure 3-13: Dynamic skin in injection wells LSH105, LSH104 and LSH103 of Wileyville field.

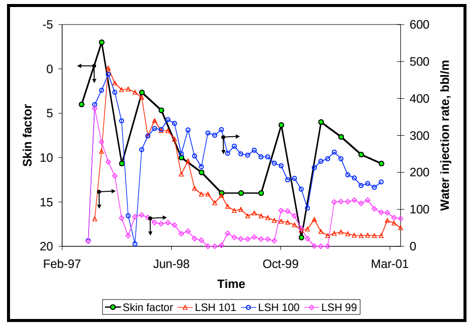

Figure 3-14: Dynamic skin in injection wells LSH101, LSH100 and LSH99 of the Wileyville field.

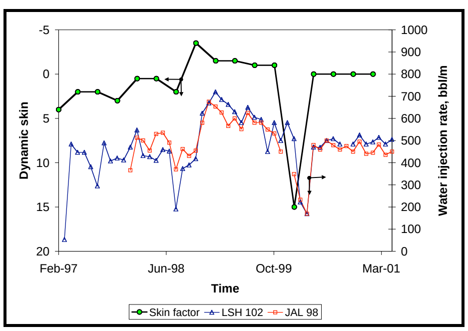

Figure 3-15: Dynamic skin in injection wells LSH102 and JAL98 of the Wileyville field.

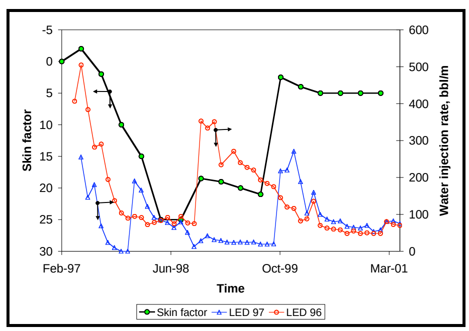

Figure 3-16: Dynamic skin in injection wells LED97 and LED96 of Wileyville field.

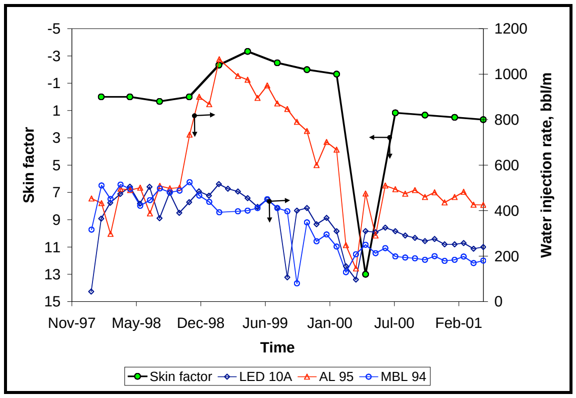

Figure 3-17: Dynamic skin in injection wells LED10A, AL95 and MBL94 of the Wileyville field.

4.0 SUMMARY

The objectives of this study were to detail efforts and techniques used to develop representative reservoir model of the Wileyville field and to provide guidelines for approaching history matching when model development is undertaken using sparse data sets. These objectives were achieved. Using sparse data sets, the reservoir model developed satisfactorily matched the behavior of the reservoir studied. This suggests that the techniques described in Chapter 2 for characterizing rock and fluid properties were appropriate.

This study shows that the rock properties could be considered uniform throughout the thickness of the reservoirs analyzed. Even though, some log analyses indicated that these reservoirs contain shales forming discontinuities and restrictions to the flow of the different phases, the results obtained suggest that the effect of these shale could be captured by varying the permeability assigned to each block in the models, and that a single layer model is a reasonable approach. These restrictions to the flow suggest that compartmentalization affects the behavior of the reservoir, and may be described in the models using permeability changes in the blocks. It can be concluded that the reservoirs studied may be appropriately described as being heterogeneous single layered.

Given the sparsely of the data, the role of the field staff proved to be crucial in determining the "acceptable" range for adjustment of the reservoir data, and for defining the "confidence" intervals for production data. In addition, the operations staff provided useful insights on the reservoirs. The field staff identified the locations of high water or gas saturations, the location of restrictions to fluid flow in the reservoirs, and reported the operating status of wells that have use for either future production or injection. The use of this data improved the "quality" of the history match by incorporating this field knowledge into the process, and thus avoided a possible numerical solution that does not represent the behavior of the fields.

This study also indicated that "apparent" skin damage varies with time and generally increases with time. The nature of the skin is dependent on matrix permeability; but also on external factors such as suspended particles and particles deposition. In the Wileyville field study, it was not possible to separate the impact of each component of skin on well performance and its change with time.

Estimates of the skin can be determined from the rate of change in the injection or production flow rates. This information can be used to optimally schedule well workovers. The results of the study suggest that the more homogeneous the reservoir rock, the greater the benefit of well stimulation reducing near wellbore damage. It is recommended to make a chemical property analysis of the emulsions that are being recovered during the workovers of the production wells. This may allow the identification of a chemical agent that could be injected into the reservoir to improve its injectivity and also reduce the time between workovers.

4.1 Wileyville field

The study suggests that waterflooding of the Wileyville field using a line-drive design was reasonable in terms of effectively displacing the oil present in the reservoir. This is particularly true in the southern portion of the reservoir where reservoir properties are remarkably uniform. The term applied to the Gordon sandstone by geologist is featureless. This implies that the sandstone is essentially homogeneous.

The study further identifies areas with low permeability and porosity. The identification of these areas supports the concept of partial compartmentalization within the reservoir. Moreover, the presence of low permeability and porosity in the central portion of the field resulted in an area of low transmissibility between the northern and southern portion of the field. Reference is made to Figure 3-9.

The quality of reservoir rock in the northern portion of the field appears to be of pure quality than the southern portion of the reservoir. To adequately develop this region of the field will require additional drilling and testing. It is possible that the injection well pattern in this portion of the field maybe need to be change to reflect the differences in rock quality between the northern and southern portion of the reservoir.

4.2 Recommendations

For study of other fields in the Appalachian basin, it is recommended that the field operations staff and the simulation team work in concert. The role of the field staff proved to be important in determining the “acceptable” range for adjustment of the reservoir data, and to define the “confidence” intervals for the production data that need to be history matched. The use of the data provided by the field staff improves the "quality" of the history match by incorporating field knowledge into the solution. This avoids a numerical solution of the problem that might not represent the behavior of the fields.

With respect to the Wileyville field, it is recommended the following strategies to improve the productivity of the reservoir be undertaken:

<u>Activation of the following as production wells</u>

W.J. Santee 4	Drill	ASAP
Jesse Shuman 206	Drill	ASAP
Jacob A. Lantz 3	Workover	ASAP
Wesley Dulaney 215	Drill	ASAP
Louise E. Dulaney 202	Workover	April 2003
L.S. Hoyt 209	Drill	September 2003
L.S. Hoyt 3	Drill	September 2004
Jennetta Chamberlain 203	Workover	January 2006
L.S. Hoyt 211	Drill	June 2006
L.S. Hoyt 208	Drill	June 2007

<u>Reconditioning of the existing production wells</u>

W.J. Santee 3	Workover	ASAP
L.S. Hoyt 204	Workover	April 2007

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Production & Research-Based Approaches for Maximizing Recovery in the Barnett Shale

during the Period 05/15/2001 to 05/14/2002

By

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Production & Research-based Approaches for Maximizing Recovery in the Barnett Shale

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Executive Summary

The Barnett Shale is a Mississippian age, very tight matrix, naturally fractured reservoir in the Ft. Worth Basin in north Texas. Unprecedented drilling activity has occurred in the current core productive area (primarily Denton, Wise and Tarrant co.), and Barnett activity continues as the second largest Texas gas field. Since 1981, field cumulative production is roughly 0.365 TCF, and is on pace to reach 1.5 TCF cumulative by 2006.

The U.S.G.S. estimates between 3.4 and 10.0 TCF of shale gas are recoverable[1] within the identified play area, making the Barnett an important piece of the economic puzzle for shale gas resources in the U.S. There are many Barnett successes for operators, but a focused, integrated study could help enhance the knowledge base and provide a springboard for improved overall ultimate recoveries. While a percentage of wells are better than 1 BCF, and refrac treatments do improve well reserves – overall gas resource <u>recovery-per-well</u> is lower than the industry needs, considering the activity level. Barnett challenges include:

- Higher liquid volumes & poorer fracture dehydration than desired for gas wells.
- The need for better baseline data, and understanding of core properties as it relates to Barnett Shale completion and production methods.
- Developing approaches and technologies to give Barnett fieldwide recovery an opportunity to approach to upper end of U.S.G.S. recoverable gas spectrum.

The Barnett is a very successful Play for a number of operators including Republic Energy, Inc. (Dallas, Texas). However, Republic has taken the pro-active step in joining the Department of Energy, Penn State University and the Stripper Well Consortium with the goal of maximizing Shale gas resources. The project focus is *underperforming wells, their known and suspected underlying causes, and improving fieldwide Shale ultimate recoveries*. Total project allotted budget is $98,550, with Republic Energy bearing a $25,550 total share and the balance funded by the U.S. DOE.

This is the first comprehensive Barnett Shale project which provides a model for other area operators, developing the link between: Rock characteristics, Fieldwide flowback, pressure and chlorides trends, and the Effect of conventional & high-rate dewatering on gas well performance.

The three project objectives are:

- Focus on improving gas recovery in wells that don't have benefit of well-connected natural fracture system.
- Characterizing mechanisms that control gas & water recovery in the reservoir at the *pore level* – using reservoir core.
- Testing reservoir drawdown limits and effect of maximum water removal, known as gas/water 'Co-Production' using Electric Submersible Pump (along w/ other lift methods like plunger lift and rod pump).

Results Summary & General Conclusions

Barnett rock is surprisingly not extremely water sensitive. It shares fracture and cleating characteristics with some coals, and has an apparent tertiary production mechanism (methane molecule desorption) at low reservoir pressure when properly dehydrated. In carefully controlled laboratory tests using Barnett core, two (of nine) commercial products were shown to enhance loadwater recovery and gas permeability recovery on core in the laboratory.

A sizeable percentage of Barnett wells suffer from liquid loading problems and poor fracture dehydration. Analysis of fieldwide flowing pressures, flowback / produced water trends, as well as chlorides trends show this to be the case. There is strong evidence that the source of high liquids production is bounding Viola or Ellenberger zones.

Republic's pro-active approach of using aggressive Co-Production dewatering improves wells that don't behave like a typical flowing, trouble free gas wells. Dewatering with rod pump has been shown to add an estimated incremental 330 MMCF / well, and plunger lift an estimated incremental 90 MMCF / well, on average. Twelve wells were included as test cases, and tests are currently ongoing. *Note that estimates of incremental production and EUR may change over time as further data becomes available, and estimates are also subject to judgemental factors.

High drawdown ESP’s (submersible pump) were used dewater high PI wells in two 30-day test cases, to liberate trapped gas as shown successful in other gas / water basins. Even with detailed pre-planning, well tests did not adequately prove / disprove the concept of liberating trapped gas within pore spaces and lowering reservoir pressure (at least in our two candidate wellbores), and operational problems were also an issue. Gas was produced from these two non-flowing wells during the test period, but in uneconomic proportions.

In conclusion, this project was designed to serve as a model for area operators and others involved in developing unconventional Shale resources. The ultimate project goal is maximizing Barnett Shale gas recovery to the economically feasible limit, through the integration of baseline research and field production approaches.

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Reservoir Characterization and Regional Activity Level

Possibly the most active natural gas play in the lower 48 states, the Barnett Shale is a Mississippian age naturally fractured reservoir in the Ft. Worth Basin in north Texas. Drilling depths are typically between 6800 to 8600 ft., and the reservoir unit has between 200 to 700 ft. of gross interval in the current core productive area (primarily Denton, Wise and Tarrant co.). From its outcrop in central Texas (Llano uplift), the unit dips northward to a maximum thickness of near 1000 ft. near the Texas / Oklahoma state line[1,2]. The Barnett shale is both a non-siliciclastic source rock and a reservoir rock, with generalized drill cuttings composition being dense, black, with a lignite-type appearance. The clay content is measured between 20-40% by volume from available samples using SEM, with smectite and illite comprising a large proportion.

The Barnett Shale is usually described as having two productive units; The massive Lower Barnett which exhibits layered reservoir behavior, and the Upper Barnett which is about 20% of the gross thickness of the Lower. The Forestburg Lime section lies between the Upper and Lower Barnett with variable thickness. The Marble Falls Lime provides the apparent seal above, while the Viola Lime provides the lower boundary for the reservoir.

Detailed work by GRI [3-7] and others have shown that the Barnett Shale exhibits dual-porosity behavior because of its limited volume, “high” permeability natural fractured system coupled with a low permeability matrix (0.001- 0.0001 md). Natural fractures trend in a NW to SE direction, while induced hydraulic fractures run NE to SW. Since roughly 1999, almost all Barnett Shale wells are currently water-fractured with 0.8 to 1.5 million gallons of fresh (slick) water at high rates (60-80 BPM), with operators moving away from MHF’s with gel performed previously. Lowering well completion costs was the primary driver for this shift, while maintaining comparable well performance. The Barnett is considered a ‘dry gas’ reservoir in general terms, but associated water and areas of condensate production are concerns as development continues. A sizeable percentage of underperforming Barnett wells have been completed across the Play, with liquid production and reservoir quality problems. This project examines these problems, gathers quality reservoir / field data, and attempts to develop solutions for improving well performance.

Current drilling activity in the Shale is impressive, and the aerial productive limits of the play have yet to be defined. 3000 to 5000 locations could be left to drill among all operators within the play. Some quick facts on area activity:

- Between 1981 and 1990, 71 wells were drilled.
- During the period between 1990 and 11/2000, 705 wells were drilled!
- 25-30 drilling rigs currently operating
- 2000 total production was over 79 BCFE, and climbing.
- 2^{nd} largest gas field in Texas.
- Field Cum-to-Date since 1981, roughly 0.365 TCF.
- At current pace, roughly 1.5 TCF cum gas by early 2006.
- Impressive well production has recently been coming from expansion southward, into NE Tarrant Co. and into the Ft. Worth city limits.

Tight natural gas demand and low cost completions will continue to fuel activity in the region; however, this in turn places a greater emphasis on the industry's production practices and artificial lift technology to maximize gas recovery as time moves on.

The principle company in this project is Republic Energy Inc. (REI) is a small, independent company which is currently the second-largest Barnett operator with over 120 wells. By contrast, over 900 have been drilled by Devon Energy (formerly Mitchell Energy & Development Corp.), the area's largest operator. The Barnett is a very successful Play for Republic and a number of operators. However, the main project focus is *underperforming wells, their known & suspected underlying causes, and improving fieldwide Shale gas ultimate recovery*.

Problem Description

Understanding factors that dictate initial well productivity (IP) and EUR are absolutely essential for maximizing gas resource utilization in this area. The U.S. Geological Survey estimates that between 3.4 and 10.0 TCF of shale gas are recoverable[1] within the identified play area, making the Barnett Shale an important piece of the economic puzzle for shale gas resources in the Lower 48 states. While a percentage of wells are better than 1 BCF, and refrac treatments improve well reserves – the industry and Barnett Shale operators need ways to ensure that overall resource recovery-per-well is maximized, especially considering the activity level and the resource opportunity that exists in this area.

Projected fieldwide, and even extending to a possible 5000 drilling locations across 175,000 ac**. (Figure 1),** this “lower” percentage recovery is leading to fieldwide ultimate recoveries toward the lower end of the U.S.G.S. recoverable shale gas spectrum (3.4 TCF estimate). Liquid production from a high percentage of gas wells (50-400 bbl/ MMCF of both formation & frac water) is compounding the problem of lower ultimate recoveries, and is also symptomatic of reservoir and completion problems. The above facts and trends are the justification for this proposal: To gather the proper baseline data, apply proven production engineering technology and develop new approaches to improve EUR’s to the economically feasible extent. The goal of the SWC is to maximize Shale gas resources, and attempt to develop solutions in working toward that goal.

WELL COMPLETION & RESERVOIR BACKGROUND

A typical completion approach (with many variations along the way) has been to fracture both the Upper and Lower Barnett (together or separately depending on barrier thickness) to increase chances of intersecting natural fracture systems. Since roughly late 1998, most Barnett Shale wells are water-fractured with 0.8 to 1.5 million gallons of fresh (slick) water at high rates (50-90 BPM), with low sand concentrations usually ramped up to less than 1.4 ppa at the tail-end of the treatment. This switch to waterfracs was driven by the need to lower well completion costs. Wells are completed without packers, using the annulus for production assistance.

Flowbacks are normally very aggressive, moving 200-300 or more bbl/hr until casing pressure declines & breaks back. Loadwater recovery from flowback is commonly in the 8-25% range, depending on geographic area.

Regarding reservoir quality - well performance appears to be a moderate-to-strong function of density porosity, natural fracture volume along with quartz content within the Shale. Reservoir communication both vertically (to bounding Viola lime and Ellenberger sand) and aerially, due to induced & natural fracture cross-communication, also likely affects well performance. **Figure 2** shows generic Barnett geologic zones and a typical zonal completion.

SPECIFIC PRODUCTION PROBLEMS (FIELDWIDE WELL REVIEW)*

- Since 1998, approx. 22% of wells (208 of 942) IP'd < 380 MCFD
- Since 1998, EUR's are projected < 500 MMCF for approx. *25% of all wells*.
- Since 1998, EUR's are projected < 250 MMCF for approx. *12% of all wells*.

* Note that estimates of incremental production and EUR may change over time as further data becomes available, and estimates are also subject to judgemental factors.

- A surprisingly high percentage of wells with high post-sales liquid production. 41% of Barnett wells > 80 bbl/MMCF water – both frac treatment & formation water. Data are a sample of 140 wells across the field.
    - Data Range = 2 – 2000 bbl/MMCF water and/or condensate. Median = 57 bbl/MMCF. Mean = 127 bbl/MMCF (for 140 well sample).

GENERAL FIELD PROBLEMS

- High water production, due to: Poor fracture dehydration & load recovery – leaving water on the reservoir, or water influx from water-bearing Viola & Ellenberger layers.
- Waterfracs have improved economics, but well performance & fracture cleanup / height containment sub-optimal in some areas.
- Pumping high freshwater frac volumes in a formation having mixed-layer clays.
- Reservoir capillary forces dominate in a very tight matrix, along with very low conductivity hydraulic and natural fracture systems.
- Difficult to overcome strong capillary forces in a very tight reservoir – thought to hamper wellbore cleanup and cause small calculated drainage areas.
- WHP decline to sales line pressure (#350-425) within 15-45 days. Very steep early-time hyperbolic decline.
- Concerns about near-wellbore water or condensate blocks.
- Degrees of lateral & vertical communication between pay & bounding layers.
- *The need for better data to relate rock characteristics to producing profiles, to uncouple geologic and well completion factors, and to develop predictive models to improve ultimate recoveries.*

Objectives Statement & Summary

The ultimate objective is to move a higher percentage of wells into the “good” Barnett well category (> 180 MMCF 1st year, slower WHP decline, etc.) using a research and production-based approach to develop baseline lab data, and try new production approaches (for this area). This type of fully integrated approach has not been applied in the Barnett Shale to date within one study.

In summary, the plan is to:

- Focus on improving gas recovery in wells that don’t have benefit of well-connected natural fracture system.
- Accurately characterize mechanisms that control gas & water recovery in the reservoir at the *pore level* – using reservoir core.
- Test reservoir drawdown limits and effect of maximum water removal, known as gas/water ‘Co-Production’ using Electric Submersible Pump (along w/ other lift methods like plunger lift and rod pump).

Our focus is on gas wells with a higher than average water-producing tendency – wells drilled in ‘non-core’ areas or ones without the benefit of a well-connected natural fracture system. **Figure 3** shows general problem areas within the current Barnett Play, and locations were core material was obtained for testing.

This is a three-phase project that includes laboratory and field components, where gas-water ‘Co-Production’ is the chief method employed to maximize gas rate. The idea of moving as much water as possible is basically untested in this reservoir. Field testing ‘Co-Production’, along with lab testing reservoir core responses to maximum drawdown at varying water saturations & with surfactant chemicals, will determine if we can maximize well EUR’s w/ this analysis.

PROJECT FUNDING LEVEL

Total estimated cost to Penn State for the performance of this subcontract was not to exceed $73,000. Republic Energy shares a $25,550 in-kind contribution in the total project cost of $98,550.

Three-Phase Work Plan

This is an ambitious, integrated study which has laboratory and field-testing components. Meeting the objectives stated above required the following three phases:

- Laboratory Pore-Level Characterization of the Shale
- Flowing Pressure Analysis of Water / Condensate Production
- Field Co-Production & Fracture Dewatering

BACKGROUND - LABORATORY PORE-LEVEL CHARACTERIZATION

Republic and Stim-Lab^{tm} (Duncan, OK) designed the proper tests to evaluate ideas about the reservoir rock and producing character, and allowed for proper scale-up of lab results to the field level.

14 sidewall core plugs were cut from one well in key Barnett shale (and bounding member) strata. This well was located in a northern, less prolific area where the Barnett can produce gas, water & condensate phases.

15 core plugs (cut from whole slabbed core) were obtained from the University of Texas Bureau of Economic Geology – from a previously cored well (a very high EUR well) in the heart of the Play from an offset operator. See Figure 3 for these locations, and their proximity to the areas of high liquid production (water & condensate)

StimLab is helping us design the proper lab test procedures for this reservoir rock. Plans for data were:

- Basic properties (porosity, klinkenberg perms, bulk grain density, etc.)
- Thin section XRD / SEM analyses
- Critical salinity tests (for Shale sensitivities to different salinity ranges & FW)
- Flowback & Regained permeability tests of Shale to fluids (various surfactant types, etc.)
- Methane desorption & determination of 'threshold pressure'

We needed quality baseline petrographic data on the Barnett from areas with different producing tendencies. <u>We want to learn mechanisms that control frac loadwater recovery, fluid sensitivity to additives, and the gas desorption potential from this Shale (as reservoir pressure is lowered).</u>

BACKGROUND - FLOWING PRESSURE ANALYSIS OF LIQUID PRODUCTION

Low calculated fractured well drainage areas (5-15 ac.) are thought to be due to hydraulic fractures which are not properly dehydrated. Data shows that long hydraulic fracs <u>are induced but may be stress sensitive</u>, and its suspected that tortuosity combined with near-wellbore liquid saturations could cause excessive reservoir energy (pressure) loss. This impacts calculated drainage radii, gas well performance and ultimately EUR's.

Evaluation of well flowing pressure trends & early-time production data were used to examine why high percentages of Barnett Shale wells suffer from natural or induced liquid problems, and aggressive approaches that can improve gas rates & EUR's.

Data gathering and interpretation consists of:

- Early & late time flowing tubing & casing pressures, pressure decline trends & gas / water rates for over 140 total Barnett wells.
- Flowing pressure differentials between tubings & casings, which signify a well's liquid production & liquid loading tendency.
- Identifying geographic areas of known problems in the Barnett, and what completion / production approaches can be used to maximize gas rate & EUR.

BACKGROUND - FIELD CO-PRODUCTION & FRACTURE DEWATERING

Properly designed field tests using submersible pumps for gas-water Co-Production comprise the core of the dewatering approach in this project. In wells with high liquid producing tendencies (for Barnett, high PI's are 0.3 – 5.0 bbl/day/psi), properly sized ESP's can provide maximum and <u>consistent</u> bottomhole pressure drawdown by removing the hydrostatic head component in wells roughly 8000' deep.

For Republic, two (2) candidate wells for ESP testing were selected (for both practical and logistical reasons) – wells in different parts of the Barnett:

- Northern, less prolific area where the Barnett can produce gas, water & condensate phases.
- Near the main (Southern) Barnett area, but in a specific location of high liquid production and some non-flowing wells. (See Figure 3 for approximate location)

Also, less-aggressive styles of Co-Production dewatering are underway for Republic:

- Rod pump in three (3) Barnett wells
- Plunger lift in seven (7) Barnett wells.

The major differences are rod pump / plunger lift methods operate with an on-off drawdown condition in wells with a lower productivity index (PI) and bottomhole pressure, while ESP's allow for a constant (and often greater) bottomhole drawdown in gas wells with a sufficient liquid PI. Results from all styles of Barnett Co-Production have been integrated and the benefits quantified.

Bulleted Summary of Overall Project Results

LABORATORY CHARACTERIZATION PHASE

- All shale zone samples showed < 0.01 md permeability. This adds to the prevailing opinion that matrix is not the primary production source, and only acts as desorption storage similar to coalbed.
- Based on the salinities tested (freshwater to 150,000 ppm), the Barnett is *not* extremely water sensitive. The one case where FW sensitivity was shown (Barnett 'C' zone, Northern well), as little as 5000 ppm controlled this sensitivity.
- Nine commercial additives were tested for improved water recovery and increased gas permeability.
    - Plexsurf WRS-C (Chemplex Inc.) improved k_{GAS} over 24%, but at 4 times the recommended concentration (2 gal/1000 gal).
    - ProSurf I Plus (1 gal/1000 gal) & Prosurf II (0.5 gal/1000 gal) measurably lowered time to recovery, and improved k_{GAS} over 5% (American Energy Services, Inc.).
    - Inflo 45S (2 gal/1000 gal) & Prosurf II (2 gal/1000 gal) improved k_{GAS} over 9% (BJ Services, Inc.).
    - Cudd RFF-1 (1 gal/1000 gal) improved k_{GAS} over 10% (Cudd Inc.).
    - The other four products either foamed and hampered flow or showed no substantial improvement for their cost.

FLOWING PRESSURE ANALYSIS OF PRODUCED LIQUIDS PHASE

- High liquids production that causes problems in Barnett wells is almost certainly not Barnett water, but fluid from sub-bounding Viola & Ellenberger zones. This is verified by flowback analyses, chlorides trends vs. time, and flowing pressures.
- Long hydraulic fractures are induced upon treatment (killing offset wells). However, low calculated drainage areas are due to stress-sensitive fractures and

liquids in the fracture (in the underperforming groups), causing high energy losses in the reservoir.

- Poor fracture dehydration occurs due to high volumes of frac water- *especially combined with high influx volumes from Viola & Ellenberger zones.*
- Northward in the Barnett, three-phase production (cond./gas/water) further compounds problems for flowing gas wells. PVT analysis verifies that free liquid exists *in the reservoir* (#6800 gas dewpoint, #3600 BHP), along with fluid from sub-bounding Viola & Ellenberger zones.
- Figure 3 shows areas of high liquids production (flowback & sales-line water).
- Early-time chlorides trends show a strong relationship with production & EUR – the higher the slope and higher the value, the poorer the well. **Figures 4, 4 (#1-5), and Figure 5** detail this trend.
- **Figures 6 & 7** show EUR is strongly inversely related to Frac Loadwater Recovery (bbl) and to Total Load Recovery (flowback + production water, bbl).
    - o < 1BCF wells make > 10,000 bbl Frac Loadwater and > 20,000 bbl Total Load.
    - o No well > 1 BCF makes over 8,000 bbl Frac Loadwater or over 18,000 bbl Total Load.
    - o A considerable number of wells lie somewhere in between this spectrum, mainly due to early-time data & sample size (n = 60).
- **Figure 8**, Gas Rate versus GLR (scf/bbl liquid) shows a bi-modal distribution and two different types of Barnett wells, when examined across the field as a whole.
- **Figure 9** shows a strong correlation between Time to WHP blowdown (days) plotted versus Ultimate recovery (EUR, MMCF).
- A sizeable percentage of Barnett gas wells need artificial lift (at various times in the well life cycle) to either prolong a flowing condition, or to overcome hydraulic forces that impede gas flow & wellbore unloading. Common options are:
    - o Swabbing, Flow intermitter, capillary or velocity strings, plunger lift, compression, rod pump, gas-lift & ESP.

FIELD CO-PRODUCTION & FRACTURE DEWATERING PHASE

- High-rate gas / water Co-Production (80-500 BWPD) was previously untested in this reservoir, and only recently become a viable option, to due more drilled acreage encountering marginal reservoir quality.
- Aggressive Co-Production in gas wells (using below-perforation ESP's w/ variable-speed drives) was the featured approach of this project, drawing on experience and success from south Texas and New Mexico Permian Basin in fractured reservoirs.
- ESP designs were finalized after data were gathered from the first two project phases (Lab Core & Flowing Pressure Analyses).

- Two candidate wells for ESP testing were chosen in:
  - Northern, less prolific area where the Barnett can produce three phases.
  - Near the main (Southern) Barnett area, but in a specific location of high liquid production and some non-flowing wells.
- Other Co-Production methods utilized by Republic are:
  - Rod pump in three (3) Barnett wells
  - Plunger lift in seven (7) Barnett wells.

RESULTS

- Even with all the pre-planning, there was operational difficulty getting good ESP tests in the 30-day period, with allotted funding. High volumes of liquid were removed to recover gas from non-flowing wells, but in uneconomic proportions.
  - Northern well cum. test production: 1400 MCF, 7259 BW
  - Southern well cum. test production: 260 MCF, 3240 BW
- Northern well encountered a csg. problem and was set above-perfs, had problems with gas-locking, and downhole cycling of fluid in recirculation pump system.
- Southern well test was cut short by producing large sand volumes, even with a gradually increased drawdown using a variable-speed drive.
- The more extreme approach of <u>downhole sand-control combined with “super sand pump” ESP's</u> would be required for permanent installations with high drawdowns. Economics of sand-control + variable-speed controlled ESP are marginal at < $3.00 / mcf gas price.

- Overall, pro-active conventional dewatering has been a success for Republic Energy in the Barnett Shale:
    - Since early 2001, 12 gas wells have required aggressive lifting.
    - Gas well dewatering has produced approx. 209.3 MMCF, 500 BC and 46,713 BW since early 2001 (12 wells).
    - Approx. undiscounted gross revenues from this approach ($3.00 gas, 82% NRI, $1 bbl disposal) are $477,000.
    - Capital investment has been approx. $202,000 total from (2) ESP tests, 3 rod pumps and 7 plunger lift systems.
    - Incremental EUR's are over 330 MMCF / well for the rod pumped wells (3), and approx. 90 MMCF for the plunger lifted wells (7) on average.

Discussion of Results

LABORATORY CHARACTERIZATION PHASE

The purpose of this phase was to conduct petrographic examination, fluid sensitivity studies and additive evaluation for enhanced flowback on the Barnett Shale. The samples spanned the Upper Barnett, Forestburg, five members of the Lower Barnett (A, B, C, D and E) and the Viola beneath the Lower Barnett **(Table 1 and Figure 2)**. X-ray diffraction (XRD), thin section (TS) analysis were performed on the various core plug samples to classify the samples and group them for further testing. Figure 3 shows the approximate locations of the Northern and Southern wells within the field, where core material was obtained for testing.

Further testing (with the same core) included fluid sensitivity by the capillary suction time (CST) testing method and flow studies with ground Barnett formation material to evaluate various additives from different suppliers on their ability to enhance and speed recovery of gas production following hydraulic fracture stimulation with water. Laboratory procedures for Capillary Suction Tests and the Flowback Additive Studies are described in detail in **Appendix 1**.

Table 2 shows different brines formulations used for testing, based on typical produced water used in water fracs in the Barnett. These fluids spanned the range of conditions encountered, from freshwater to an extreme of 150,000 ppm brine (which in some cases, this high salinity flowback water from other wells is used for fracing).

Table 3 gives the results of the routine air permeability and Helium porosity measurements. All shale zone samples showed less than 0.01 md permeability. This suggests that matrix permeability is not the primary source production and only acts as desorption storage similar to coal. Based on these results it was decided to conduct fluid sensitivity and flow studies using ground shale samples.

Table 4 gives the results of the capillary suction time (CST) tests. Fluids evaluated represented several potential cases for fluid exposure based on available and potential fracturing fluid sources. The samples for CST tests were grouped as given in Table 1. Typical values for CST ratio vary from 0.5 for no sensitivity to >45 for extreme sensitivity. However, the values must be compared to a control (usually freshwater) for evaluating results for any sample. Most of the samples evaluated showed little fluid sensitivity to brief (<1 hour exposure) to the various fluids tested. Only one sample from the Lower Barnett C zone in the Northern well showed any fluid sensitivity and this was only to freshwater. Addition of as little as 5,000 ppm salinity controlled this sensitivity.

Table 5 shows the flow study results. Initial testing results showed it was most valid to rely on Time to gas recovery and Amount of water remaining in the pack compared to a control for evaluating the various products. Time to recovery is compared. This is the time at the point where the relative permeability first stabilizes. Equivalent time to recovery gives the time to the point where the gas permeability following treatment reached the same relative permeability value as the pretreatment gas flow. A shorter value for equivalent recovery time would indicate enhanced load water recovery. A higher relative permeability may also result due to the lower water saturation (Sw). A time for equivalent recovery is not given if the post treatment gas flow failed to reach the pretreatment gas permeability.

Nine (9) products were evaluated in the initial screening tests with the composite Lower Barnett samples from the Southern well. Water recovery was good for all products compared to the controls. However, the controls were conducted with composite samples from the Lower Barnett Northern well core plugs. Therefore, for the Southern well screening tests it would be best to compare relative results for the different products and reserve control comparison to the Northern well tests.

Plexsurf WRS-C from Chemplex was evaluated at two concentrations to determine if increasing the concentration improved effectiveness. Since the treatments were performed on the same pack, only one retained water mass was measured at the end. At the 0.5 gal/1000 gal concentration, the treatment proved ineffective at improving the relative gas permeability. Increasing the concentration to 2 gal/1000 gal increased relative permeability, but it did not shorten the time to recovery. This may be due to a slight increase in viscosity of the solution (not measured) with the higher additive concentration lengthening the fluid displacement time with gas. Unfortunately, budgeting did not allow for evaluation of all candidates at several concentrations.

Two products created foam upon gas return flow. These were SSO-21 and CatFoam. The foam trapped gas within the core resulting in reduced retained relative gas permeability. Two products were selected from the initial screening for further study with the Northern Well Lower Barnett samples. These products were American Energy Services Prosurf I and II combination and BJ Services Inflo 45S which both improved the relative gas permeability and had low retained water saturation within the pack. *The Plexsurf WRS-C was not chosen to continue as it only performed at four times its recommended concentration.*

Evaluation of the two products in the two groups of composite samples from the Northern Well showed less water recovery than the Southern Well samples - indicating that the character of the formation and/or age of the samples affected the water retention properties. Compared to the control samples both additives lowered the retained water compared to the control. The AES Plexsurf product was slightly less effective than the BJ 45S product in improving the relative permeability. Neither dominated in decreasing time to equivalent recovery with BJ product favored in the A,B sub zones and the AES product in the C,D,E sub zones.

Conclusions from tests performed indicate that the Barnett shale most likely produces from a fracture network as matrix permeability is extremely low. The Barnett shale is not extremely water sensitive and that the current practice of fracturing with available water with low salinity most likely creates little flow impairment. Additives to improve water recovery and therefore lower water saturations with net improvement in relative gas permeability may be beneficial and should be further explored in larger scale laboratory tests and/or field scale evaluations where conditions can be controlled to provide reasonable comparisons.

FLOWING PRESSURE ANALYSIS OF PRODUCED LIQUIDS PHASE

As described in detail previously, over 41% of sampled Barnett wells make over 80 bbl/MMCF water after being on production, whereupon adequate fracture dehydration does not occur with the available reservoir energy. It is quite clear that liquids in the reservoir and wellbore suppress Shale gas ultimate recoveries, and liquids are one of the primary factors (both in the form of large volume waterfracs and formation water influx)) leading to the current percentages of underperforming wells (see Specific Production Problems list, Page 4).

The actual origin of liquids, and their impact in relation to important factors (like geologic structure, stratigraphy and tectonics), is a matter of much debate and speculation amongst experienced the Barnett Shale operators. The data developed within this study are arguably the most complete, most robust and best integrated, to begin to define and analyze: Field liquids / production problems, Provide spatial patterns for problems, and Incorporate operational and production solutions to solve these problems and improve well production and EUR's. Key parameters worthy of analysis and understanding are:

- Field Chlorides trends by well, and groupwise versus gas production
- Fractured well flowback and total liquid recovery versus production
- Correlation between WHP blowdown time versus gas production

Chlorides

Spatially across the field, patterns in chlorides values versus time are very reliable correlating variable with well performance and gas ultimate recovery. Data from Figure 4 shows robust data sets from all across the currently active Barnett area. Data from Figures 4 (1) – 4 (5) detail the spatial pattern of chlorides trend both by areas (labeled #1-5 on Figure 4) and chlorides trends versus EUR (Figure 5).

Referring to Figure 4 for placement of trend areas:

- Figure 4 (1) – A depletion-style dry gas area with a low chlorides trend over time. These are high EUR wells and strong performers.

- Figure 4 (2) – A depletion-style dry gas area having some variability in liquids, but a relatively flat chlorides trend over time. These are high EUR wells and strong performers.
- Figure 4 (3) – A high liquids, gas/water/condensate producing area and an area with quite different reservoir characteristics. These are low-to-marginal EUR wells, and showed a much higher chlorides slope over time.
- Figure 4 (4) – A wide group of wells on the edge of a known high liquids, variable production area of the Barnett. These are low-to-marginal EUR wells, showing aggressive chlorides trends, especially when compared to Locations 1 & 2.
- Figure 4 (5) – This is a group of high chlorides, high slope trending wells in an area of known liquids production. These are low EUR wells, mixed with some non-flowing wells. Interestingly, most wells in this area had an IP > 1100 MCFD, but rapidly declined.

- Chlorides sampling program specifics: All wellhead samples, pulled in 25-ml bottles, all analyzed by the same laboratory. Sampling Program Frequency:
    - Frac fluid itself (either from frac pit or working tanks during the job)
    - Every 8 hours during flowback
    - 1^{st} five days down sales line (5 samples)
    - Normally at 30, 60, 90 day etc. intervals

This type of program allowed for some repeatability and a respectably large data set from over 80 Barnett Shale wells (sometimes 20 data pts. for a given well). The figures above don't include all wells, but the group with the most complete data sets.

- Figure 5 shows the strong correlation between maximum chlorides value reached (max. minus a 5000 ppm frac fluid baseline value) and EUR. As a rule in this data set, wells projected over 1 BCF will have chlorides < 50,000 ppm. It is our opinion that wells having > 50,000-70,000 ppm chlorides (especially early in the well life) are communicating with lower bounding zones, by porosity bands, faulting, fractures or karsted Viola and Ellenberger zones.

Liquid Recovery Versus Production

EUR is strongly inversely related to Frac Loadwater Recovery (bbl) and to Total Load Recovery (flowback + production water, bbl) – FOR SOME WELLS. In a “normal” reservoir, high load recovery after fracture is a good sign. Often, a 65% load recovery is thought of as optimal. However, in a dual-porosity, fractured system – fracture load recovery analysis often sends mixed signals to operators.

- Figures 6 & 7 look at Frac Loadwater and Total Load (Frac Load + Cumulative Water), respectively.
    - They show < 1BCF wells make > 10,000 bbl Frac Loadwater and > 20,000 bbl Total Load.
    - No well > 1 BCF makes over 8,000 bbl Frac Loadwater or over 18,000 bbl Total Load.
    - A considerable number of wells lie somewhere in between this spectrum, mainly due to early-time data & sample size (n = 60).

- Figure 8, Gas Rate versus GLR (scf/bbl liquid), shows a bi-modal distribution and two types of Barnett wells, when examined across the field as a whole. Given all the reservoir variability, two or three general trends are not surprising.

WHP Blowdown Over Time Versus Ultimate Recovery

Possibly the most dramatic and telling correlation developed in this project is Figure 9, Correlation between Days to Blowdown vs. EUR (MMCF). While line pressures vary, they don’t vary too far (#320-450) to make a basic correlation. Line pressures were normalized, and project ultimate recoveries were plotted.

- This graph, especially when considered with all available liquids & chlorides data, shows that Barnett production is a function of the following:
    - Porosity and permeability
    - Zonal communication
    - Fracture conductivity (& pressure-dependent conductivity)
    - Liquids in the reservoir and inside the wellbore

Underperforming Barnett wells normally blowdown to line pressure in less than 30 days, and need assistance with liquid removal pro-actively to attain an economic well EUR.

FIELD CO-PRODUCTION & FRACTURE DEWATERING

For wells already drilled within the Barnett Shale, as well as for future wells in many areas – proactive and aggressive gas / water Co-Production is the best option for moving underperforming wells into the "acceptable" part of the EUR continuum. This is especially true in a firm gas price environment (> $3.00 / mcf), where prices allow operators to take production approaches that were uneconomic at lesser gas prices.

One main project objective was to feature high rate Co-Production dewatering using electric submersible pump (ESP) below perforations. The basic premise of moving <u>maximum</u> water to unload wellbore, to liberate trapped gas and lower reservoir pressure to allow desorbed gas production, was basically untested in this reservoir until now. Aggressive Co-Production (using plungers and rod pumps) has been successful for Republic Energy, but dewatering with ESP (30-day tests) was not an economic success. **Figures 10 and 11** show the general schematic of plans. After first successfully proving Barnett Shale dewatering benefits, it was planned to enhance economics and water-handling feasibility by moving water (regardless of water source) back into a lower bounding zone while Co-Producing gas. This has been proven successful in some oil and gas provinces.

After evaluating candidate wells and gathering data from the other project phases for months, the following ESP approach was set into motion using Baker-Hughes Centrilift's system. A recirculation system was chosen instead of a shrouded ESP, for purposes of motor cooling and ability to fit inside 5.5", #17 N-80 production casing (a standard for Barnett completions since 1999, up from 4.5" prior). At near 8000', with concerns about solids / sand / fluids, this was recognized as a challenging environment for all personnel involved. The recirculation system is shown in **Figure 12**.

- Designed to: Maximize drawdown & minimize gas interference, improve motor cooling and provide an alternative to 'slim-line' equipment.

Results & Timeline (ESP)

Two candidate wells were: Northern well (same well rotary sidewall cores were cut for analysis), & Well near main (Southern) Barnett area, but in a specific location of high liquid production and some non-flowing wells.

- February-May 2001- Identify problem geographical areas and high liquid PI areas. Decide on two candidate wellbores.
- August-November 2001- Design below-perfs ESP's with Centrilift[TM] to dewater gas wells, drawing on experience from other gas well dewatering basins.
- November 2001-February 2002 - Wait for proper timing for core acquisition, and proper timing for installation & operation.
- March-April 2002 – Prepare locations & piping for installation. Perform wellwork and begin 30-day ESP dewatering tests.
- April-May 2002 – Pull ESP, and evaluate operational & production data.

Even with all the pre-planning, we still encountered operational difficulty in getting good ESP tests during the 30-day period, and with the funding allotted. We made gas from non-flowing Barnett gas wells, and moved a high amount of liquid to recover the gas, but in uneconomic proportions.

NORTHERN WELL –
Pre-test condition: Dead (loaded, non-flowing new drill well)
Initial 'co-production' test rates: 120-160 MCFD, 300-400 BWPD
Estimated Design PI (bbl/day/psi drawdown) = 0.3
Actual PI (bbl/day/psi drawdown) = 0.5 – 0.2
Cumulative test production: 1400 MCFD, 7259 BW
Operational problems: Stuck unit above most of Barnett perfs due to casing abnormality. Decision was made to set unit at top part of Barnett zone, just above abnormality. Setting above perfs was not preferential, in a gassy environment. Had problems with gas-locking, and downhole cycling of fluid in recirculation pump system.

SOUTHERN WELL –
Pre-test condition: Dead (loaded, non-flowing for 12 months, Year 2000 well)
Initial 'co-production' test rates: 80 MCFD, 450 BWPD
Estimated Design PI (bbl/day/psi drawdown) = 0.2
Actual PI (bbl/day/psi drawdown) = 4.0 – 5.0 ! (very high for a Barnett well)
Cumulative test production: 260 MCFD, 3240 BW
Operational problems: Set unit below perfs. ESP would not move consistent fluid, even with over 7000' of fluid in wellbore and a very high initial PI. ESP appeared to move

solids, may have had casing failure. Well test cut short by producing large sand volumes, even with a gradually increased drawdown using a variable-speed drive. ESP teardown showed solids damage, even using Centrilift's best "super sand pump".

With good / complete well tests, the reservoir probably would have responded favorably – given the well PI's and the gas well history from the Southern well (prior cum 143 MMCF, IP 1200 MCFD).

Results (Plunger lift and Rod Pump Methods)

- Overall, pro-active Co-Production dewatering has been a success for Republic Energy in the Barnett Shale:
  - Since early 2001, 12 gas wells have required aggressive lifting.
  - Gas well dewatering has produced approx. 209.3 MMCF, 500 BC and 46,713 BW since early 2001 (12 wells).
  - Approx. undiscounted gross revenues from this approach ($3.00 gas, 82% NRI, $1 bbl disposal) are $477,000.
  - Capital investment has been approx. $202,000 total from (2) ESP tests, 3 rod pumps and 7 plunger lift systems.
  - Incremental EUR's are over 330 MMCF / well for the rod pumped wells (3), and approx. 90 MMCF for the plunger lifted wells (7) on average*.

(*Note incremental production and EUR estimates are subject to judgemental factors).

While these methods also have operational challenges (especially with solids & corrosive fluids on rod wells), aggressive conventional dewatering is successful at improving well revenue and EUR. This is especially true taking non-flowing (loaded and dead) Barnett wells and improving EUR's in the 200-450 MMCF* range with rod pumps.

Conclusions & Recommendations

This is the first comprehensive Barnett Shale project which provides a model for other area operators, developing the link between: Rock characteristics, Fieldwide flowback, flowing pressure and chlorides trends, and the effect of conventional & high-rate dewatering on well performance. Republic Energy has had good success with their dewatering program in terms of improving production and EUR, but economics of high-rate dewatering are best supported by a + $3.00/mcf gas price environment, due to associated costs of liquid handling and downhole challenges (especially rod and ESP). The project had three objectives:

- Focus on improving gas recovery in wells that don't have benefit of well-connected natural fracture system.
- Characterizing mechanisms that control gas & water recovery in the reservoir at the *pore level* – using reservoir core.
- Testing reservoir drawdown limits and effect of maximum water removal, known as gas/water 'Co-Production' using Electric Submersible Pump (along w/ other lift methods like plunger lift and rod pump).

These objectives were achieved using three separate phases: Laboratory, Flowing Pressure Analysis, and Field Operations Design and Testing.

Barnett rock has an extremely tight matrix, often naturally fractured, and is not (surprisingly) extremely water sensitive. It shares fracture and cleating characteristics with some coals, and has an apparent tertiary production mechanism (methane molecule desorption) at low reservoir pressure when properly dehydrated. Two commercial products were shown to enhance loadwater recovery and gas permeability recovery on core in the laboratory.

A sizeable percentage of Barnett wells suffer from liquid loading problems and poor fracture dehydration. Analysis of fieldwide flowing pressures, flowback and produced water trends, as well as chlorides trends show this to be the case. There is strong evidence that the source of high liquids production is bounding Viola or Ellenberger zones.

Aggressive and pro-active Co-Production dewatering improves wells that don't behave like a typical flowing, troublefree gas wells. Dewatering with rod pump has been shown to improve EUR's roughly 330 MMCF / well, and plunger lift 90 MMCF / well, on average (for the 12 wells tested in this project)*.

High ESP-style drawdowns are required to properly remove water from high PI wells, to liberate trapped gas as shown successful in other gas/water basins. Even with detailed pre-planning, we encountered operational ESP problems and well tests were not adequate to prove / disprove the concept of liberating trapped gas within pore spaces and lowering reservoir pressure (at least in our two candidate wellbores). Gas was recovered with this method, but in uneconomic proportions.

Recommendations

- Fracturing wells with clean freshwater appears non-damaging, but further evaluation of alternatives high-volume (+1 MM gal.) waterfracs in marginal rock quality areas is recommended.
- Field tests should be conducted with the two best-performing commercial loadwater recovery additives, to enhance early-time fracture dehydration.
- In areas of marginal rock quality to be drilled or areas where far-field communication (vertical & lateral) is suspected, operator should prepare to move high water volumes very early in the life of the gas well to maximize EUR and performance of the asset.
- The choice of dewatering method is best suited to a case-by-case basis, regarding which artificial lift method performs best to maximize gas.
- Regarding ESP, the extreme approach of <u>downhole sand-control combined with "super sand pump" ESP</u> is probably required for permanent installations with high drawdowns. Economics of sand-control + variable-speed controlled ESP are marginal at < $3.00 / mcf gas price.

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Table 1
Sample List, Test Assignments and Groupings

Southern well — **3" plugs cut vertically into slabbed core**
(Can't visually distinuish A-E zones on Lower)
Well near Denton / Tarrant Co. border

Depths (top)	Depths (bottom)	Barnett Zone	Thin Sec Prep	Thin Sec Analysis	XRD	CST	Good Plugs	Additive Study
7107	7107	Upper	X	X	X	X		
7119	7119	Forestburg	X					
7124.1	7124.3	Forestburg						
7124.7	7124.9	Forestburg	X					
7128	7128	Forestburg	X	X	X	X		
7135	7135	Forestburg	X					
7141	7141	Forestburg	X	X				
7147	7147	Forestburg	X					
7154	7154	Lower	X					7 Screening Tests Performed with Combined Samples
7161	7161	Lower	X					
7168	7168	Lower						
7177	7177	Lower	X	X	X	X		
7184	7184	Lower	X	X				
7188	7189	Lower	X	X				
7197	7197	Lower	X	X				
7201	7201	Lower	X	X				
7210	7210	Lower	X	X				
7218	7218	Lower	X	X				
7222	7223	Lower	X	X	X	X		

Northern Well — **3" plugs cut as rotary sidewall plugs**

Well approx. 18 mi. north of Southern Well

Depths (top)	Barnett Zone	Descript.	Thin Sec Prep	Thin Sec Analysis	XRD	CST	Good Plugs	Additive Study
7349.5	Upper		X	X				
7370	Upper		X	X	X	X[a]	X	
7374.5	Upper	dense	X	X			X	
7710	Lower A	did not recover						
7720	Lower A	hot GR in A	X	X	X	X		Two Tests
7860	Lower B	mid B	X	X	X	X		
7900	Lower C	mid C	X	X	X	X		
7937	Lower D	normal D zone, no fault	X	X		X[b]		
7947	Lower D	main fault D zone	X	X	X		X	Two Tests
8005	Lower E	mineral filled fractures	X	X			X	
8023	Lower E	small fault & central E	X	X	X		X	
8055	Lower E	another E lobe	X	X			X	
8071	Lower E	open E fractures	X	X	X	X		
8085	Viola	karsted Viola (very top)	X	X	X-N/C			
8184	Viola	karst breccia	X	X	X	X		

a - combine samples to have enough material

b - 7937 similar to 7947, CST on one and XRD on other for enough material

Table 2

Brine Formulations Used in CST And Flow Studies

Component	Concentration (g/L) 5,000 ppm	5,000 ppm + 1% KCl	50,000 ppm	150,000 ppm
NaCl	6.19	6.19	61.9	184.8
$CaCl_2$ - $2H_2O$	1.85	1.85	18.5	55.5
$MgCl_2$ - $6H_2O$	0.77	0.77	7.7	23.1
KCl	0	10	0	0

Table 3

Routine Air Permeability And He Porosity Analysis of Northern Well Rotary Sidewall Samples

Sample I.D.	Depth feet	Helium Porosity %	Permeability (800psi) Air md	Klinkenberg md	Grain Density g/cm	Lithology
14	7370.0	*	<0.001	<0.001	*	Upper
13	7374.5	*	<0.001	<0.001	*	Upper
9	7900.0	*	0.005	0.002	2.46	Lower C
7	7947.0	*	<0.001	<0.001	*	Lower D
6	8005.0	*	<0.001	<0.001	*	Lower E - fractures?
5	8023.0	3.4	0.010	0.004	2.50	Lower E
4	8055.0	*	<0.001	<0.001	*	Lower E
2	8085.0	4.7	0.103	0.081	3.03	Viola Fm. - Pyrite Clast

* unable to measure

Table 4

Capillary Suction Time (CST) Results

Southern Well

Depth (ft)	Interval	Fluid	Blank Time (no sample)	Sample (sec)	CST Ratio
7107	Upper	150,000 ppm Brine	9.30	37.4	3.0
		50,000 ppm Brine	8.40	26.2	2.1
		5000 ppm + 1%KCl	8.20	26.7	2.3
		5000 ppm Brine	8.20	27.9	2.4
		Freshwater	8.10	29.6	2.7
7128	Forestburg	150,000 ppm Brine	12.20	39.2	2.2
		50,000 ppm Brine	10.60	31.5	2.0
		5000 ppm + 1%KCl	10.50	28.1	1.7
		5000 ppm Brine	10.50	28.1	1.7
		Freshwater	10.20	32.8	2.2
7177	Lower	150,000 ppm Brine	12.20	24.2	1.0
		50,000 ppm Brine	10.60	29.0	1.7
		5000 ppm + 1%KCl	10.50	26.1	1.5
		5000 ppm Brine	10.50	16.0	0.5
		Freshwater	10.20	29.8	1.9
7222/7223	Lower	150,000 ppm Brine	12.20	39.2	2.2
		50,000 ppm Brine	10.60	28.2	1.7
		5000 ppm + 1%KCl	10.50	19.6	0.9
		5000 ppm Brine	10.50	24.0	1.3
		Freshwater	10.20	25.1	1.5

Northern Well

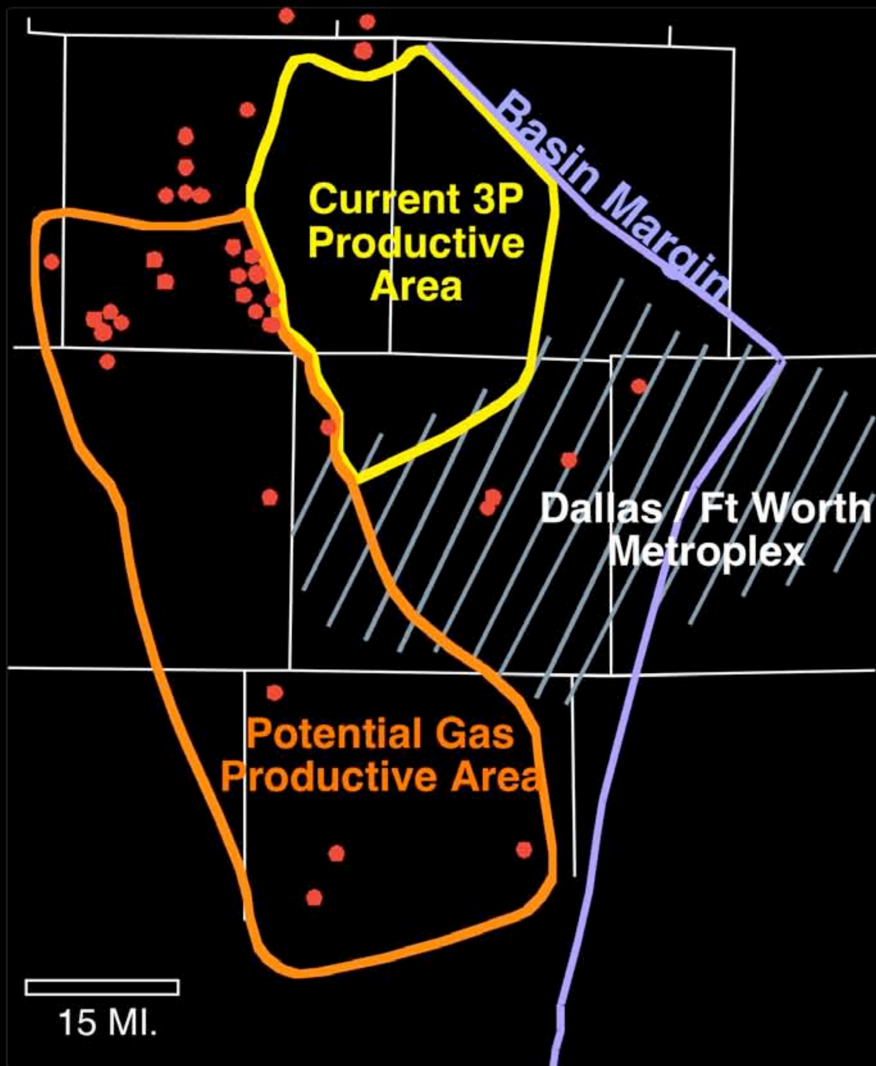
Sample #		Fluid	Blank Time (no sample)	Sample (sec)	CST Ratio
7349.5/7370	Upper	150,000 ppm Brine	11.90	56.1	3.7
		50,000 ppm Brine	10.70	48.3	3.5
		5000 ppm + 1%KCl	9.70	39.3	3.1
		5000 ppm Brine	9.70	51.1	4.3
		Freshwater	9.60	54.5	4.7
7720	Lower A	150,000 ppm Brine	11.90	48.7	3.1
		50,000 ppm Brine	10.70	49.6	3.6
		5000 ppm + 1%KCl	9.70	41.8	3.3
		5000 ppm Brine	9.70	38.1	2.9
		Freshwater	9.60	39.2	3.1
7860	Lower B	150,000 ppm Brine	11.90	23.5	1.0
		50,000 ppm Brine	10.70	21.5	1.0
		5000 ppm + 1%KCl	9.70	23.8	1.5
		5000 ppm Brine	9.70	19.9	1.1
		Freshwater	9.60	18.3	0.9
7900	Lower C	150,000 ppm Brine	11.90	57.3	3.8
		50,000 ppm Brine	10.70	55.3	4.2
		5000 ppm + 1%KCl	9.70	48.9	4.0
		5000 ppm Brine	9.70	43.2	3.5
		Freshwater	9.60	85.2	7.9
7937	Lower D	150,000 ppm Brine	11.90	29.5	1.5
		50,000 ppm Brine	10.70	22.1	1.1
		5000 ppm + 1%KCl	9.70	21.2	1.2
		5000 ppm Brine	9.70	20.0	1.1
		Freshwater	9.60	28.4	2.0
8071	Lower E	150,000 ppm Brine	9.30	29.2	2.1
		50,000 ppm Brine	8.40	24.2	1.9
		5000 ppm + 1%KCl	8.20	19.3	1.4
		5000 ppm Brine	8.20	22.8	1.8
		Freshwater	8.10	24.1	2.0
8184	Viola	150,000 ppm Brine	11.90	24.1	1.0
		50,000 ppm Brine	10.70	17.9	0.7
		5000 ppm + 1%KCl	9.70	14.9	0.5

TABLE 5 - Chemicals To Aid Dewatering of Barnett Shale Following Fracture Stimulation

Sample	Treatment in 50000ppm Cl brine	Supplier	Pack Weight Wet (g)	Dried Pack Weight (g)	Pack Water Remaining (g)	Sw Estimate From Control (%)	Time to Max. Recovery (min)	Time to Equivalent (min)	Gas Data: Time to Max. Recovery (min)	Gas Data: Kg before (md)	Gas Data: Kg After (md)	Gas Data: Increase in Kg (%)	Comment
Southern Well' Lower Barnett	.5gal/1000gal Plexsurf WRS-C	Chemplex, Snyder, TX					28.2	N/A*	24.2	4691	4514	-3.77	
	2gal/1000gal Plexsurf WRS-C	**Chemplex, Snyder, TX**	**34.921**	**34.731**	**0.190**	**2.2**	**24.2**	**24.0**	**47.3**	**4514**	**5637**	**24.88**	
	1gal/1000gal CESI Chemical LB-1327	CESI, Duncan, OK	35.318	34.894	0.425	5.0	31.2	28.0	29.2	3906	3981	1.92	
	1gal/1000gal CESI Chemical LB-1325	CESI, Duncan, OK	35.168	34.876	0.292	3.4	12.1	12.0	12.0	6938	6994	0.81	30-100 mesh
	1gal/1000gal Prosurf I plus 0.5gal/1000gal Prosurf II	**American Energy Services**	**35.189**	**34.917**	**0.273**	**3.2**	**21.0**	**17.5**	**23.0**	**4496**	**4698**	**4.49**	
	2gal/1000gal Inflo 45S	**BJ Services**	**31.939**	**31.763**	**0.177**	**2.1**	**29.2**	**40.0**	**46.3**	**6377**	**7009**	**9.91**	
	2gal/1000gal Inflo 102 Experimiental	BJ Services	35.298	34.728	0.570	6.7	49.4	N/A	44.3	8283	8160	-1.48	
	1gal/1000gal Cat-Foam**	Clearwater, Inc., Pittsburgh, PA	33.175	33.010	0.165	1.9	31.3	N/A	37.2	6922	5509	-20.41	Foamed
	2gal/1000gal SSO-21M	Halliburton Energy Services	36.503	34.750	1.753	20.6	32.3	N/A	27.2	6092	782.9	-87.15	Foamed
Northern Well' Lower A,B	2gal/1000gal Inflo 45S Aborted and Repeated	BJ Services	35.893	34.754	1.139	13.4	27.0	21.0	27.0	5740	6069	5.73	
	1gal/1000gal Prosurf I plus 0.5gal/1000gal Prosurf II	American Energy Services	35.593	34.040	1.554	18.3	20.2	N/A	15.1	7413	7316	-1.31	
Northern Well' Lower C,D,E	2gal/1000gal Inflo 45S	BJ Services	35.688	34.894	0.794	9.3	10.1	12.0	14.1	5933	6288	5.98	
	1gal/1000gal Prosurf I plus 0.5gal/1000gal Prosurf II	American Energy Services	35.866	34.952	0.913	10.8	13.1	9.0	10.0	6224	6295	1.14	
	1 gal/1000 gal Cudd RFF-1	Cudd Pumping Services	34.931	34.873	0.058	0.7	17.2	43.3	54.4	6039	6693	10.83	Foamed
Control	Control No Gas, Caswell 2 Lower		42.937	34.441	8.496	100.0							
	Control After Gas, Caswell 2 Lower		36.391	34.697	1.693	19.9							

*Did not reach equivalent permeability value
**Primary product TR-A1 precipitated in brine, secondary product CatFoam used
Bold = Best performing products upon testing

Figure 1 - Barnett Shale Development Upside



Acreage Position within Potential Gas Productive Area

Wise	75,000
Parker	25,000
Johnson	75,000
Montague	?
Total	175,000

* 35 wells outside this area

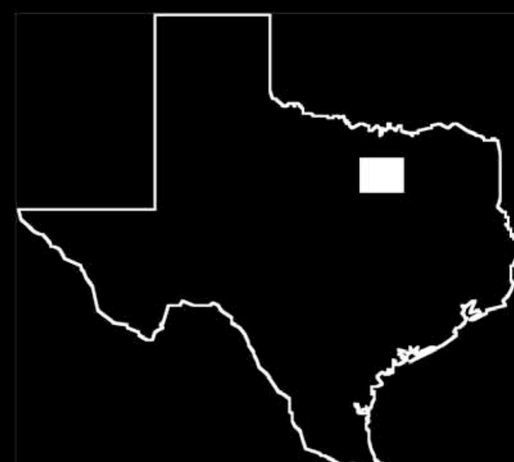
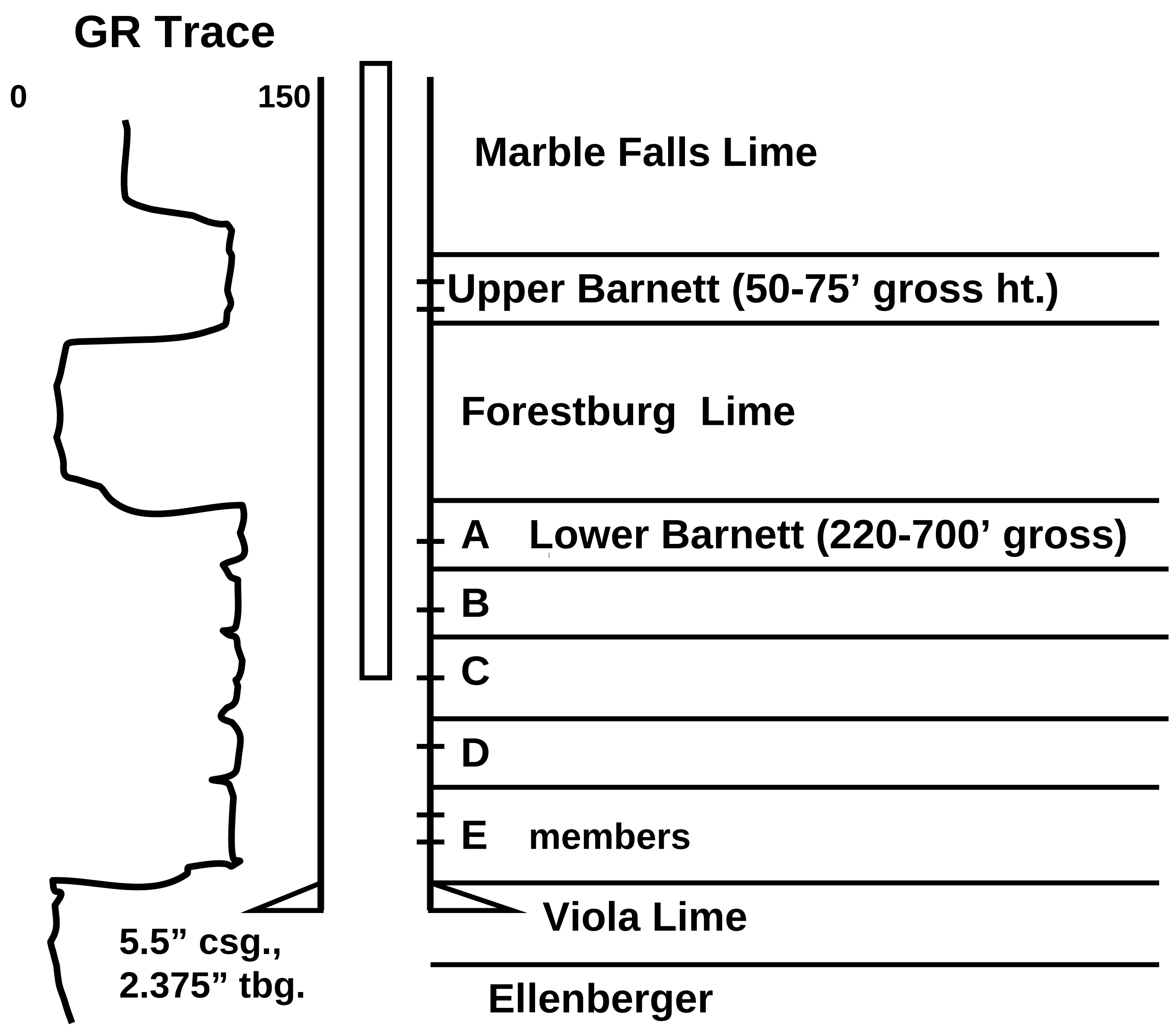


Figure 2 - Stratigraphic Column & Completion



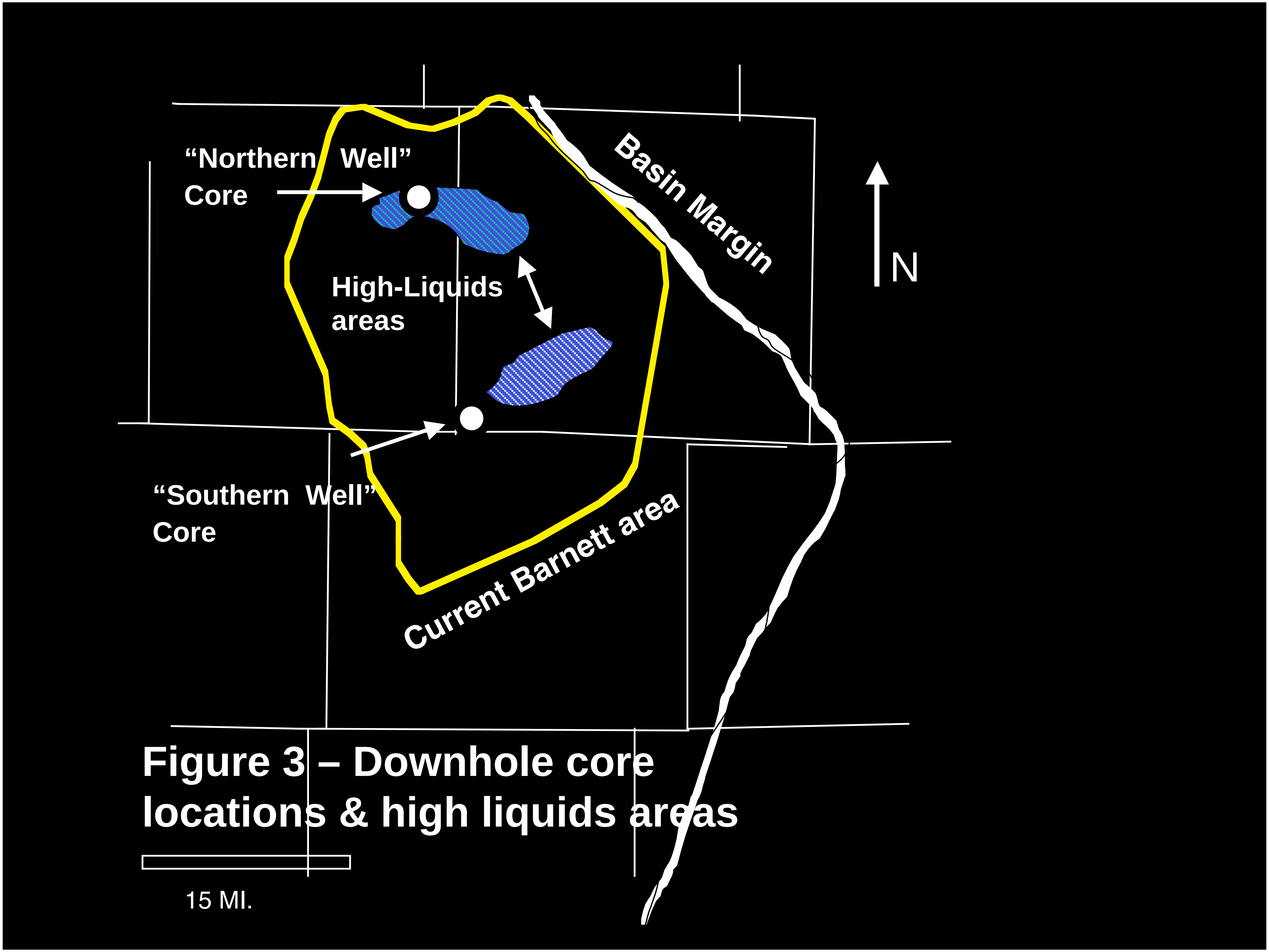


Figure 3 – Downhole core locations & high liquids areas

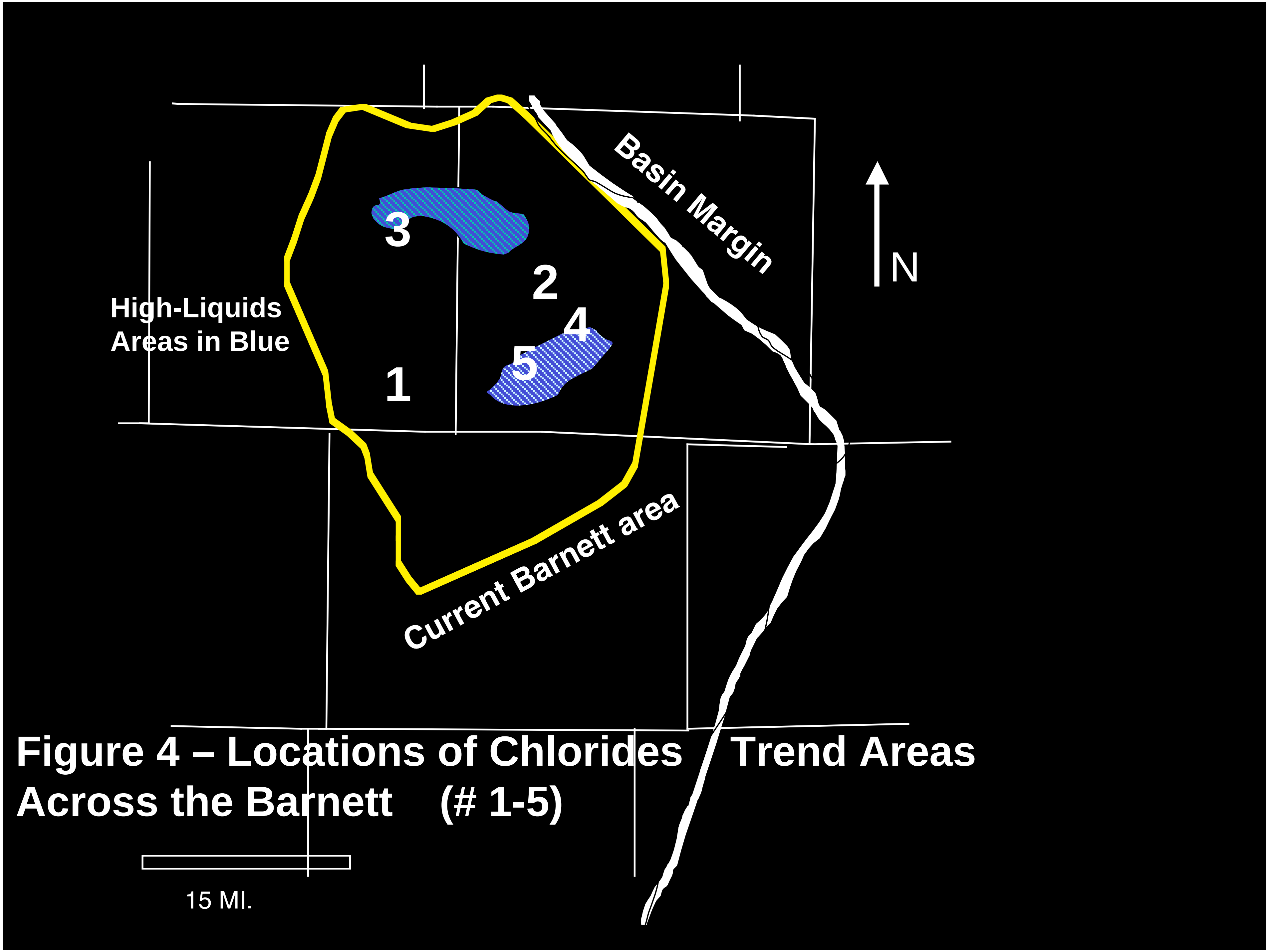


Figure 4 – Locations of Chlorides Trend Areas Across the Barnett (# 1-5)

Figure 4 (1) - 'Dry-Gas' Wells -Chlorides vs. Time

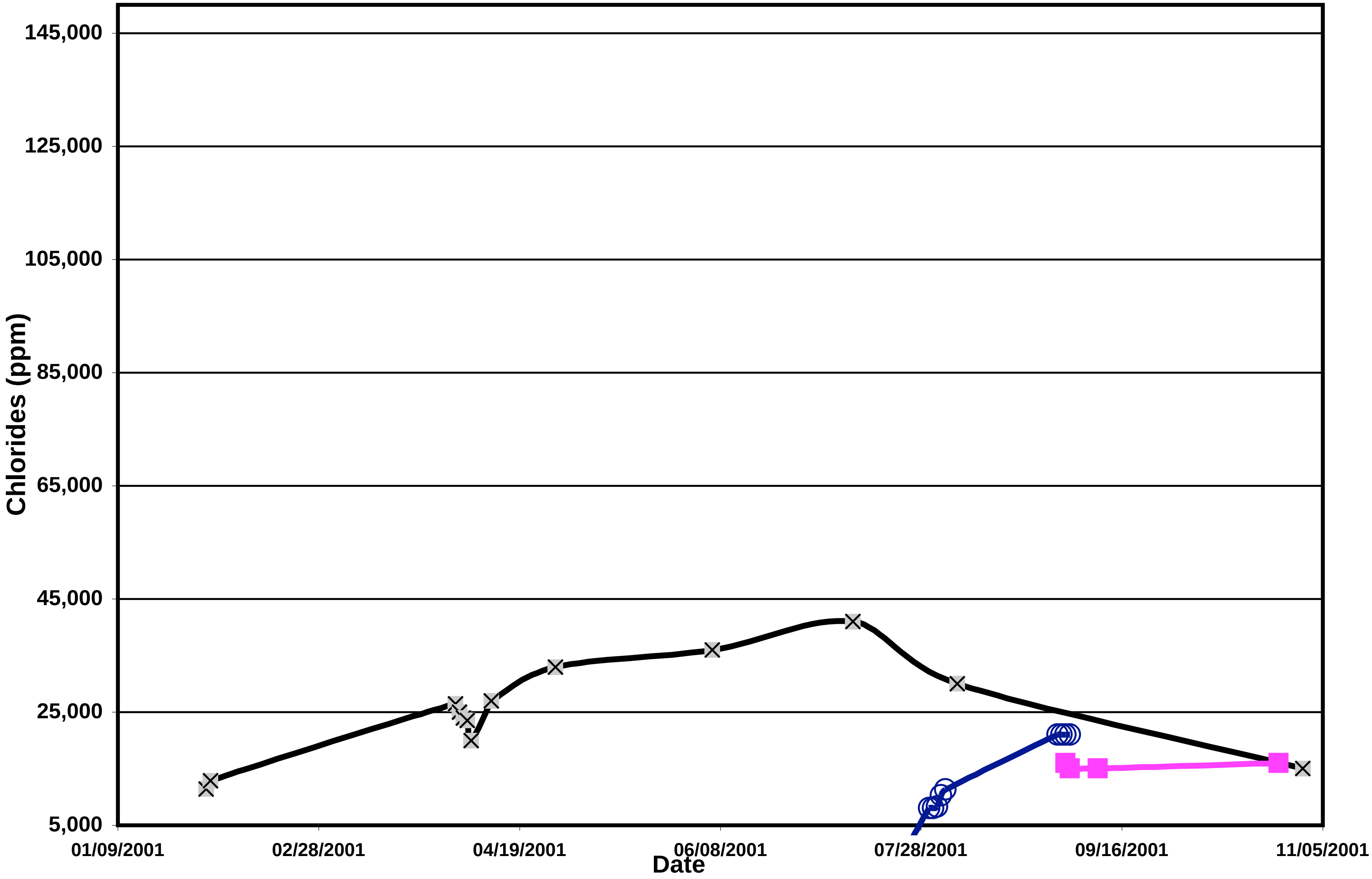
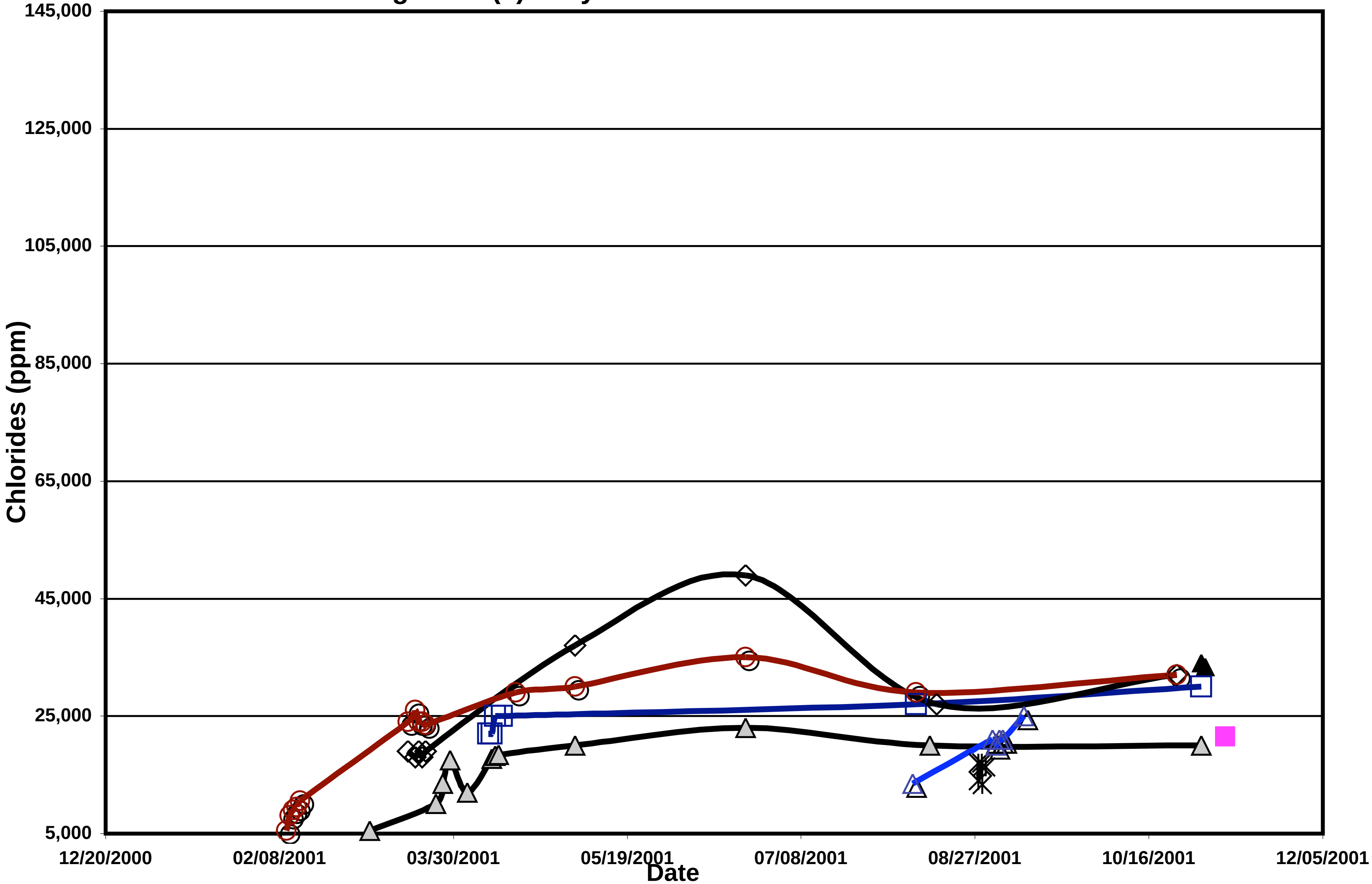


Figure 4 (2)- 'Dry Gas' wells - Chlorides vs. Time



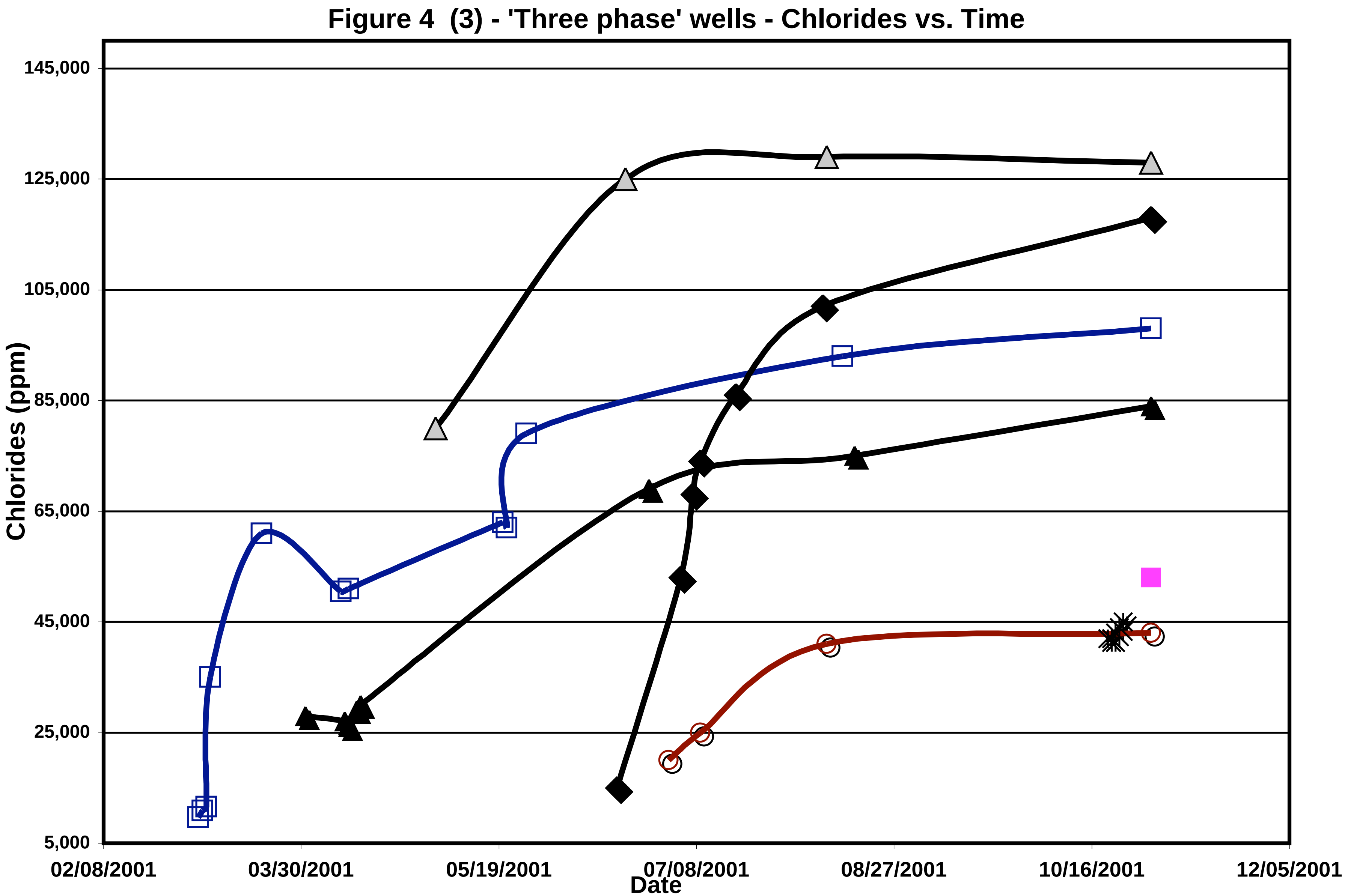


Figure 4 (3) - 'Three phase' wells - Chlorides vs. Time
Chlorides (ppm)
145,000
125,000
105,000
85,000
65,000
45,000
25,000
5,000
02/08/2001
03/30/2001
05/19/2001
07/08/2001
08/27/2001
10/16/2001
12/05/2001
Date

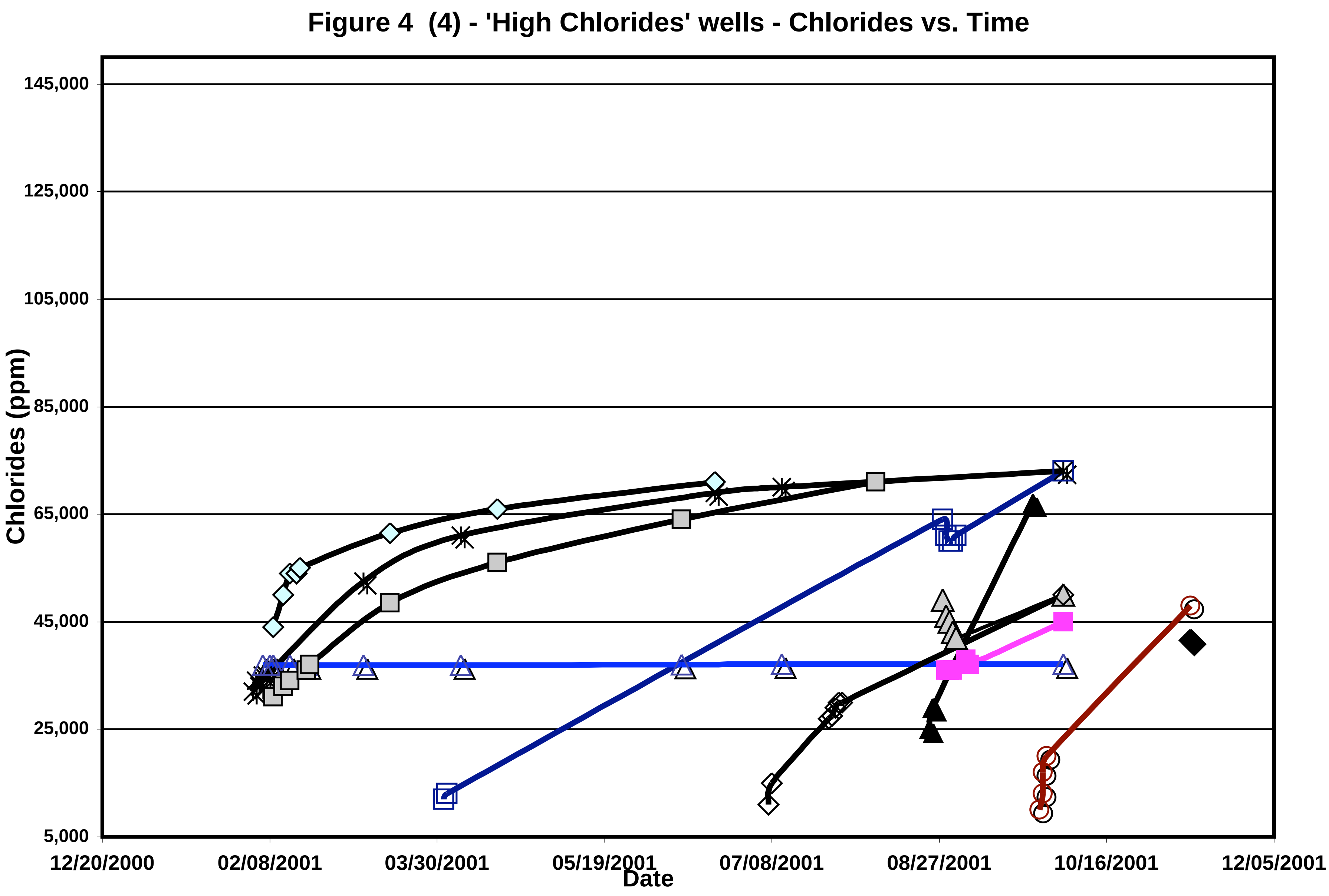


Figure 4 (4) - 'High Chlorides' wells - Chlorides vs. Time
Chlorides (ppm)
145,000
125,000
105,000
85,000
65,000
45,000
25,000
5,000
12/20/2000
02/08/2001
03/30/2001
05/19/2001
07/08/2001
08/27/2001
10/16/2001
12/05/2001
Date

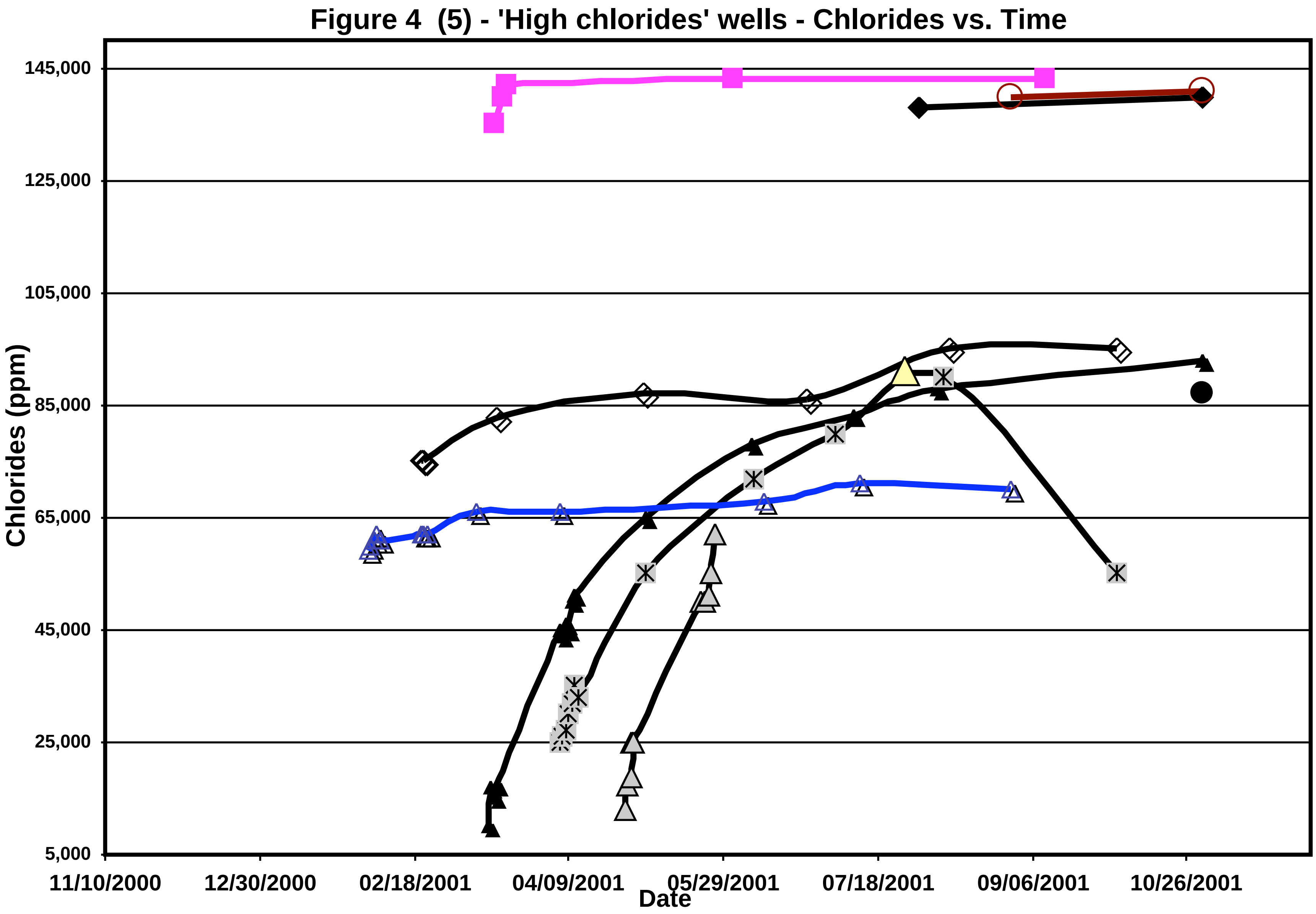


Figure 4 (5) - 'High chlorides' wells - Chlorides vs. Time
Chlorides (ppm)
145,000
125,000
105,000
85,000
65,000
45,000
25,000
5,000
11/10/2000
12/30/2000
02/18/2001
04/09/2001
05/29/2001
07/18/2001
09/06/2001
10/26/2001
Date

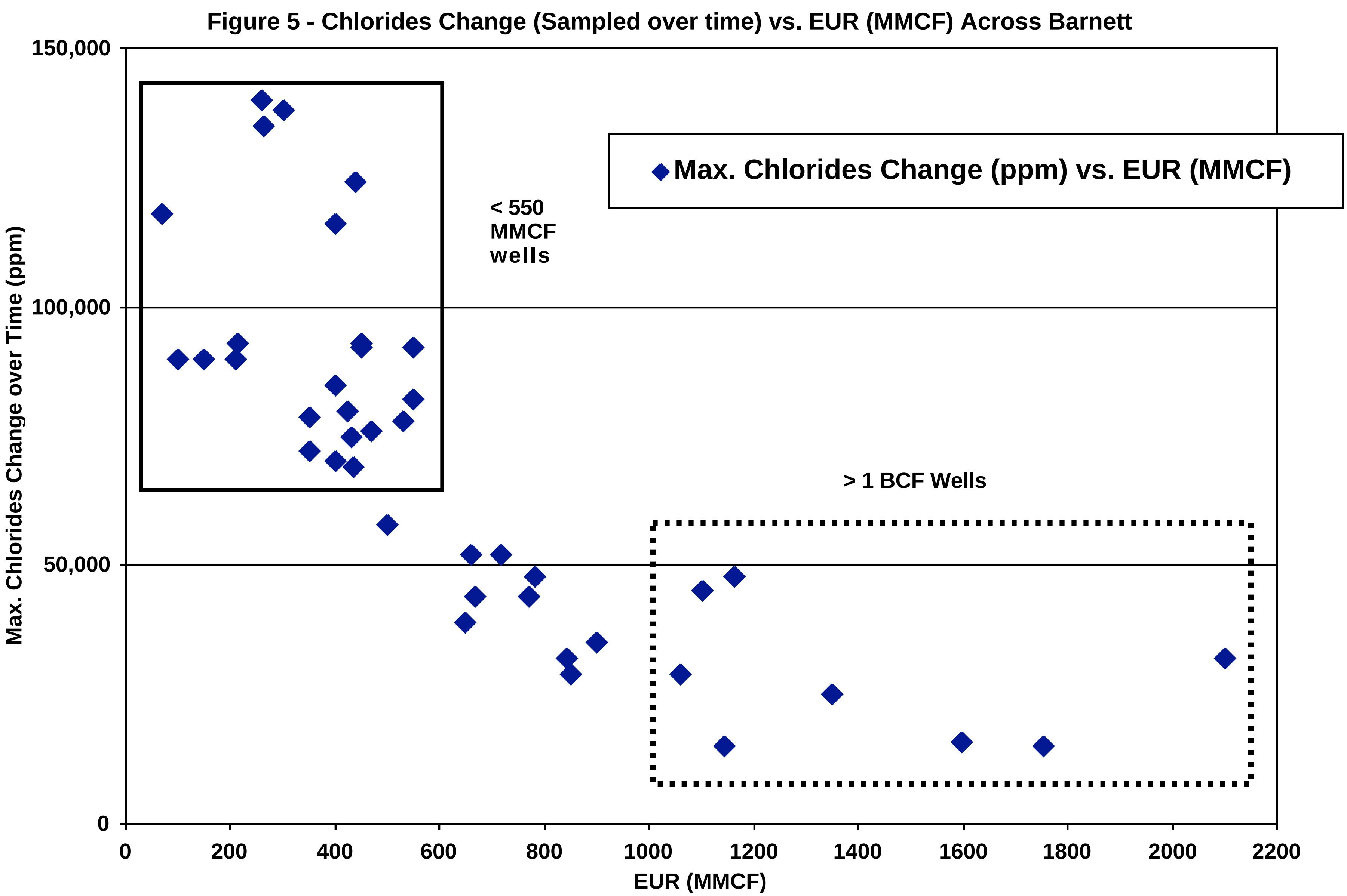
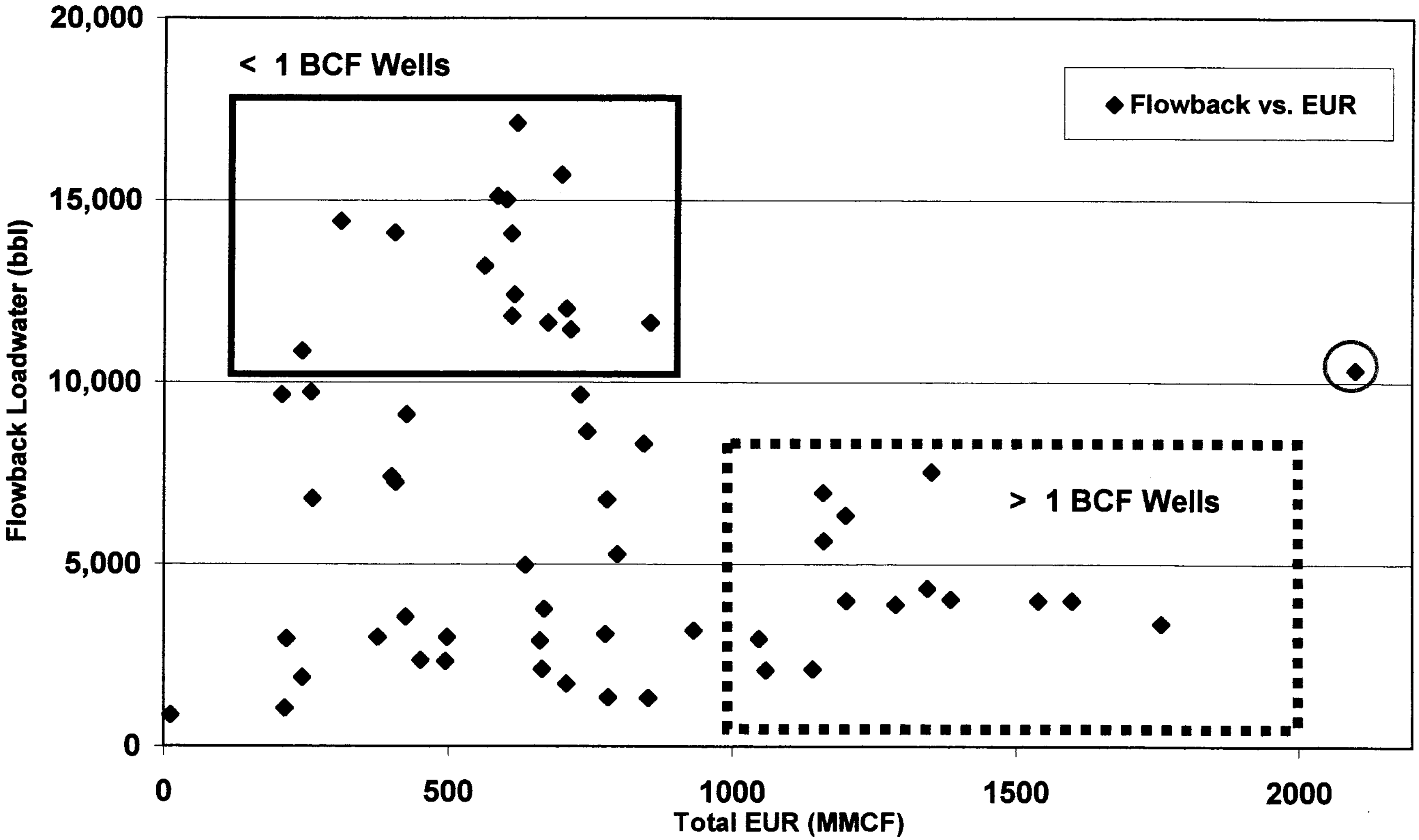


Figure 5 - Chlorides Change (Sampled over time) vs. EUR (MMCF) Across Barnett
150,000
100,000
50,000
0
Max. Chlorides Change over Time (ppm)
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
EUR (MMCF)
Max. Chlorides Change (ppm) vs. EUR (MMCF)
< 550 MMCF wells
> 1 BCF Wells

Figure 6- Frac Flowback Water (bbl) vs. EUR (MMCF)



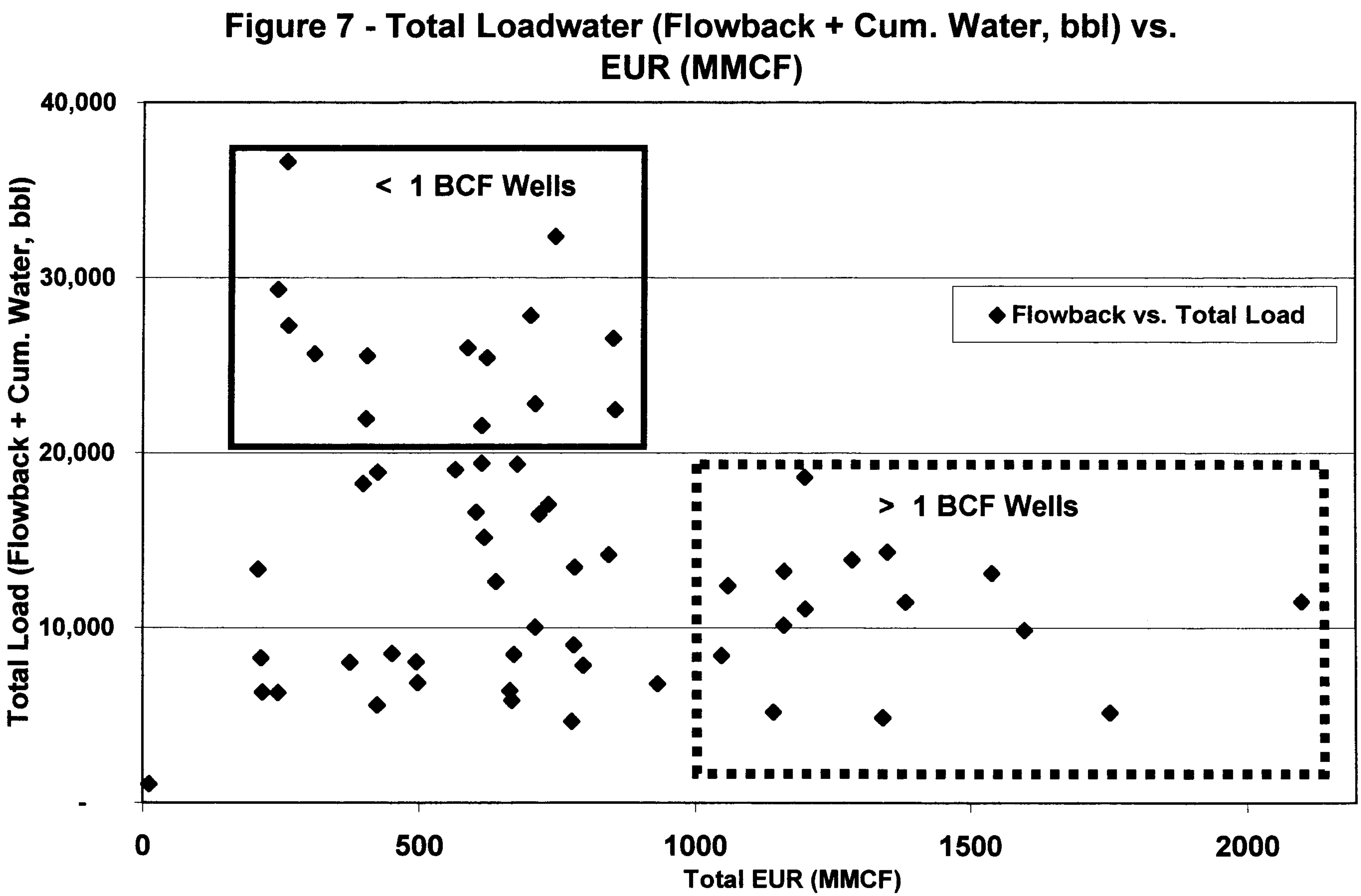


Figure 7 - Total Loadwater (Flowback + Cum. Water, bbl) vs. EUR (MMCF)
40,000
30,000
20,000
10,000
-
Total Load (Flowback + Cum. Water, bbl)
< 1 BCF Wells
> 1 BCF Wells
◆ Flowback vs. Total Load
0
500
1000
1500
2000
Total EUR (MMCF)

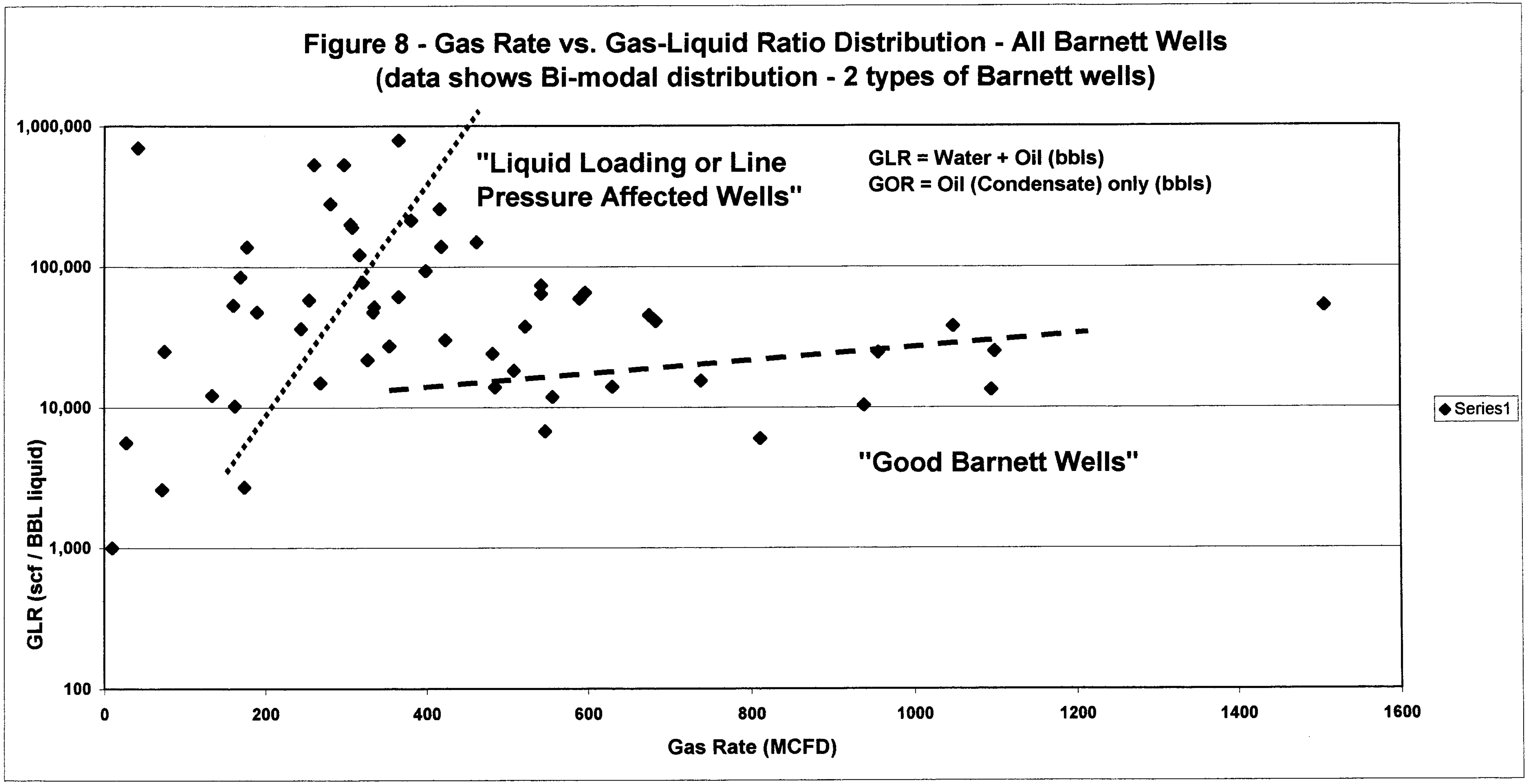


Figure 8 - Gas Rate vs. Gas-Liquid Ratio Distribution - All Barnett Wells
(data shows Bi-modal distribution - 2 types of Barnett wells)
"Liquid Loading or Line Pressure Affected Wells"
GLR = Water + Oil (bbls)
GOR = Oil (Condensate) only (bbls)
"Good Barnett Wells"
Series1
GLR (scf / BBL liquid)
1,000,000
100,000
10,000
1,000
100
0
200
400
600
800
1000
1200
1400
1600
Gas Rate (MCFD)

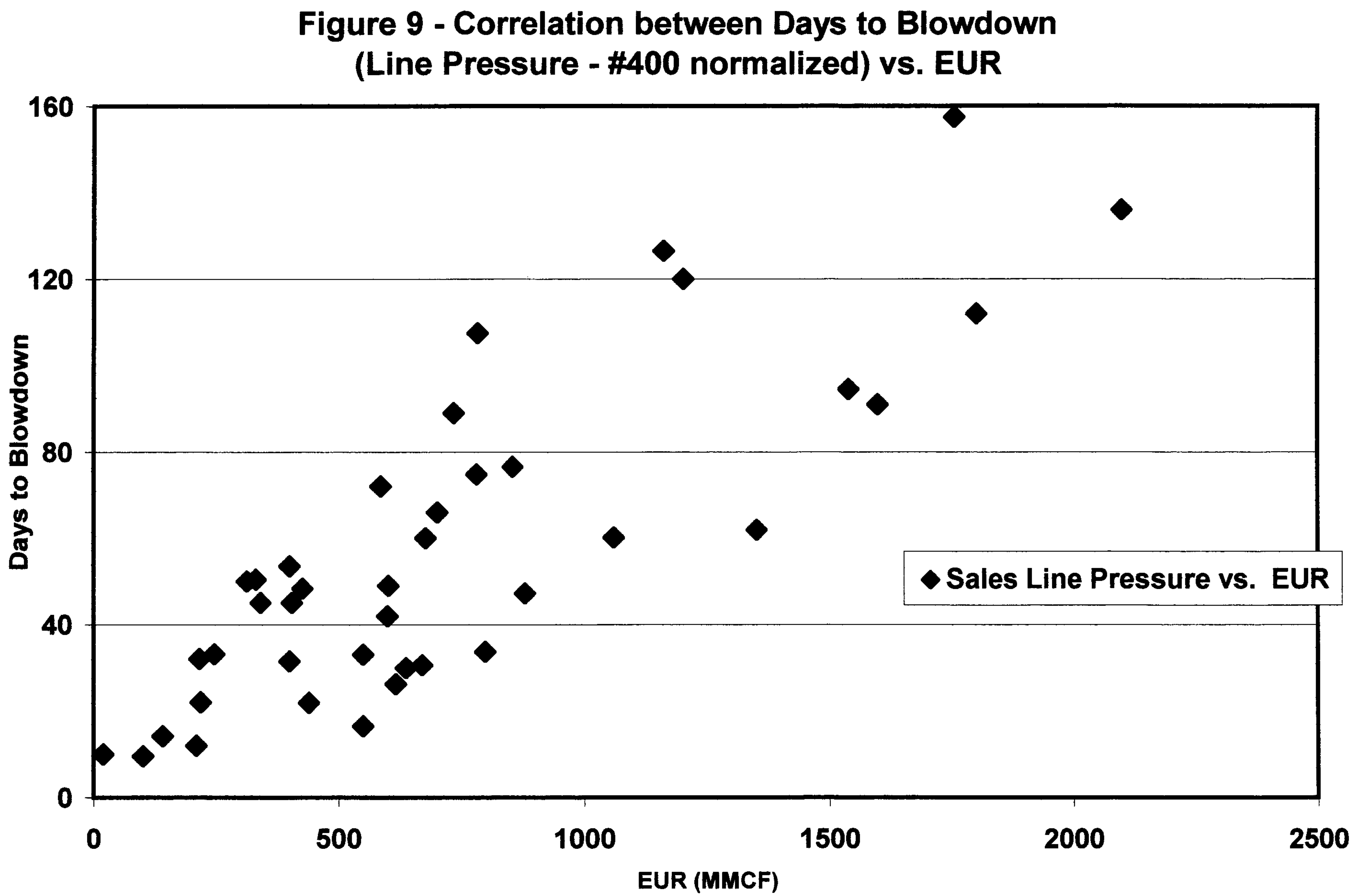


Figure 9 - Correlation between Days to Blowdown
(Line Pressure - #400 normalized) vs. EUR
160
120
80
40
0
Days to Blowdown
0
500
1000
1500
2000
2500
EUR (MMCF)
Sales Line Pressure vs. EUR

Figure 10 - ESP Co-Production, Testing Dewatering Below-Perfs

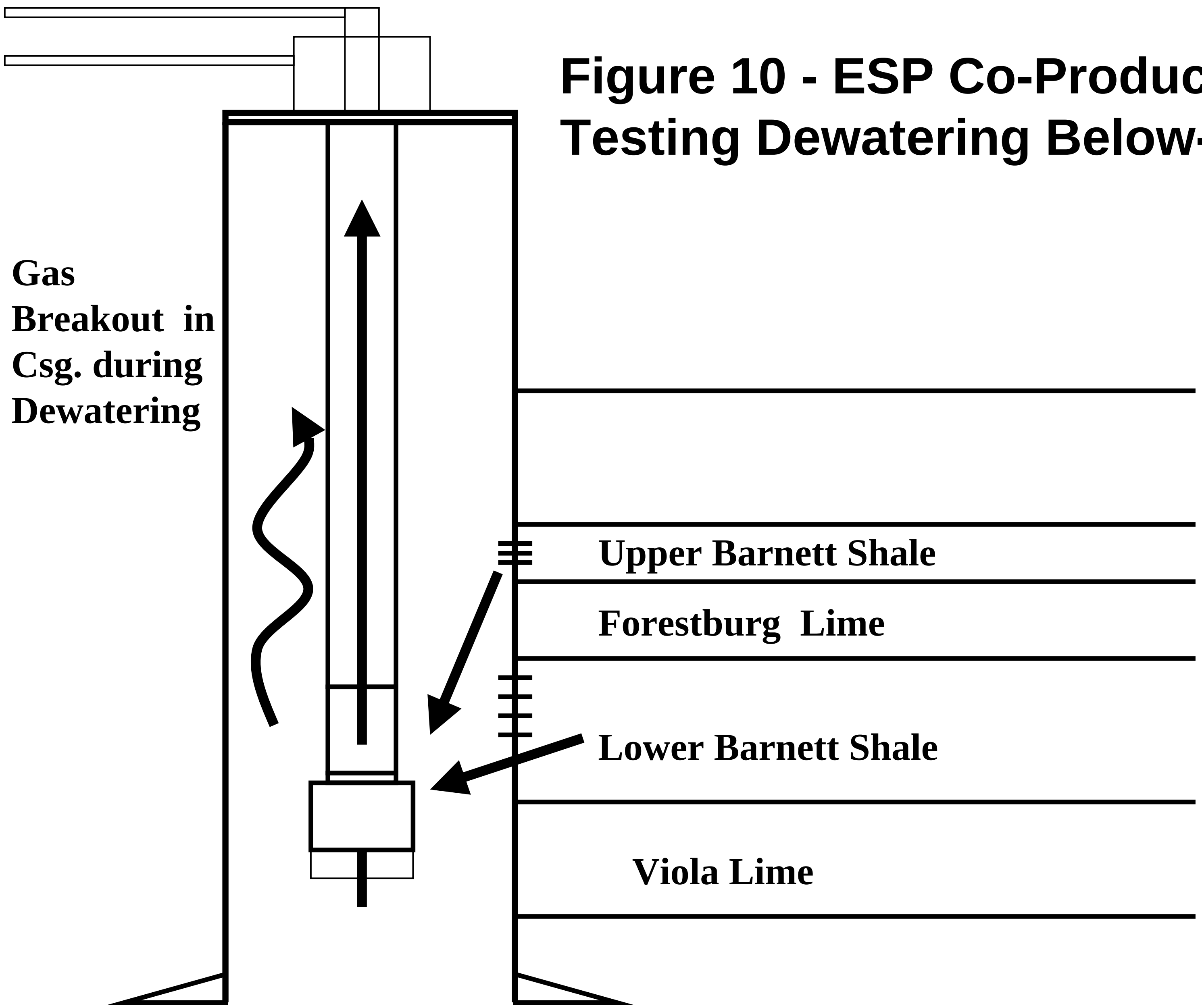


Figure 11 - ESP Co-Production Using Downhole Dewatering – After Successful Test of Surface Co-Production

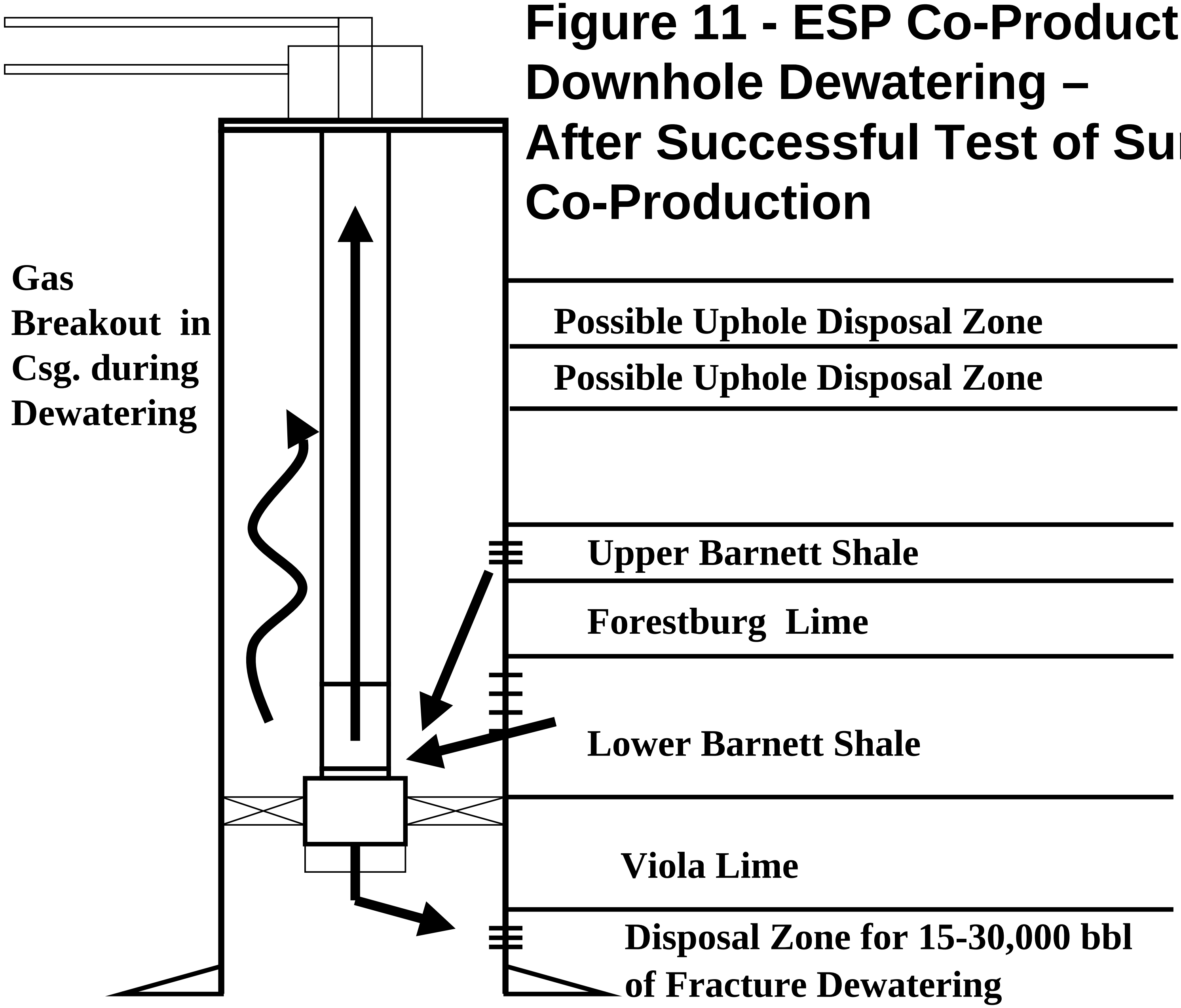
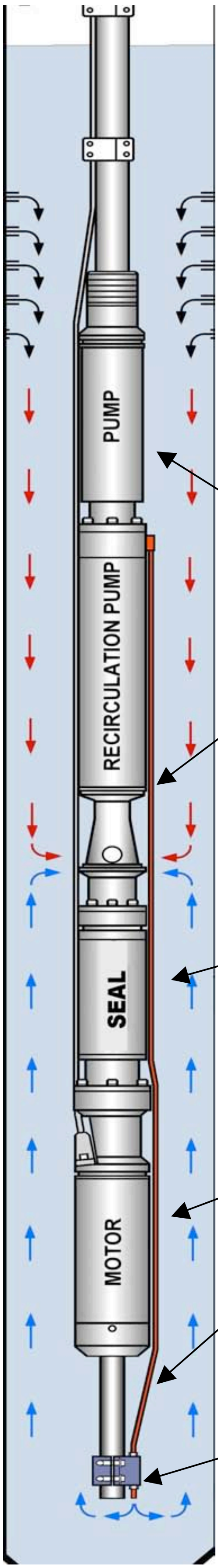


FIGURE 12 – RECIRCULATION PUMP APPLICATION

PATENTED

PRODUCTION ZONE



PUMP
- SIZE LIKE A NORMAL INSTALLATION
- STANDARD OPTIONS CAN BE USED

RECIRCULATION SYSTEM
- INTAKE FOR BOTH PUMPS

SEAL
- CONVENTIONAL

MOTOR

RECIRCULATION TUBE

TUBING CLAMP

Recirculation Pump System used to:

- maximize well drawdown
- minimize gas interference
- improve motor cooling in low volume wells
- provide an alternative to slim line equipment

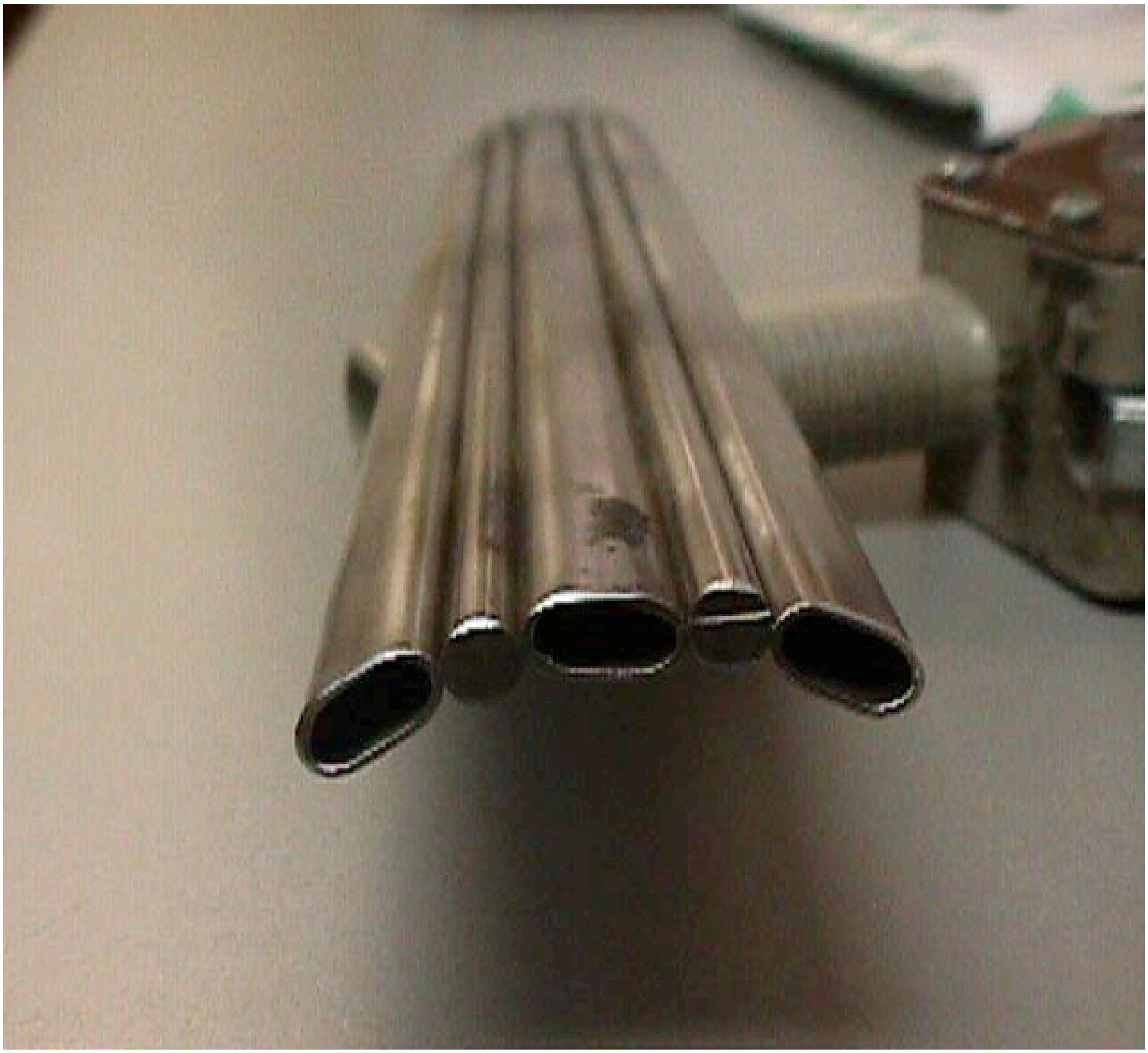


Figure 13
Confinement Cell Used For Flow Studies - Stim-Lab[tm]

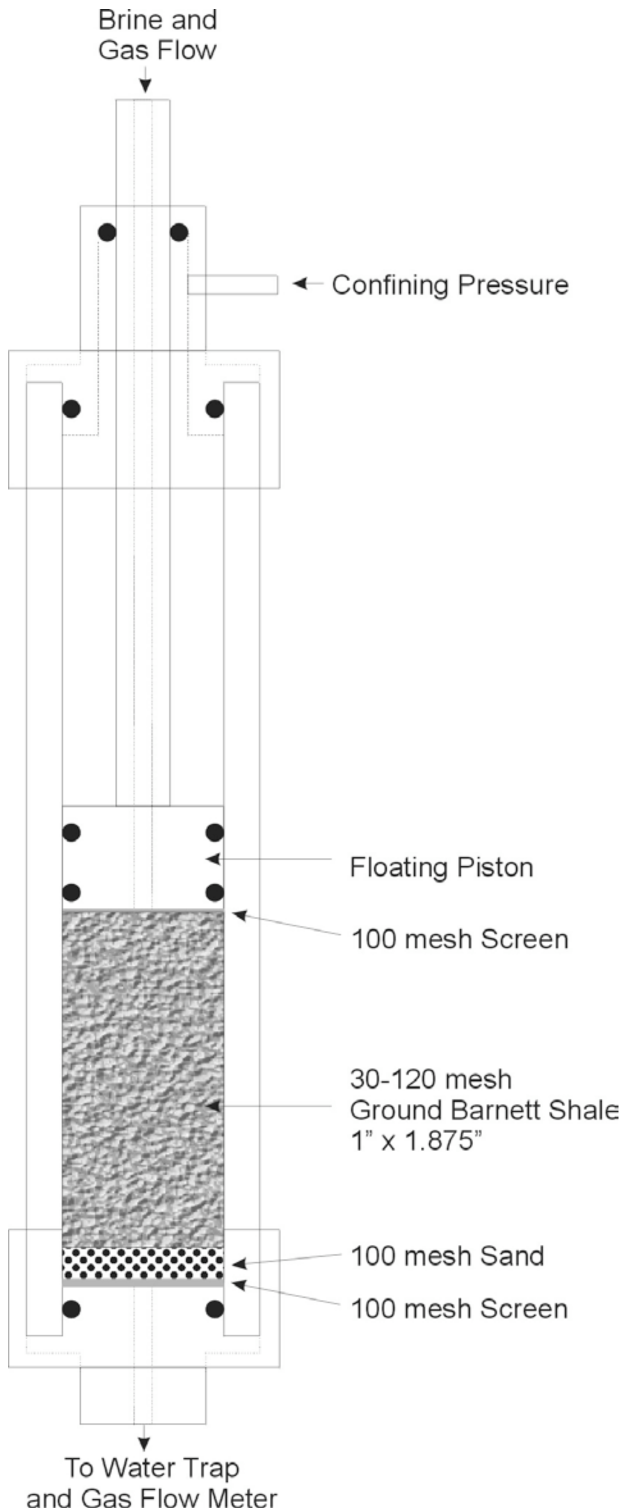
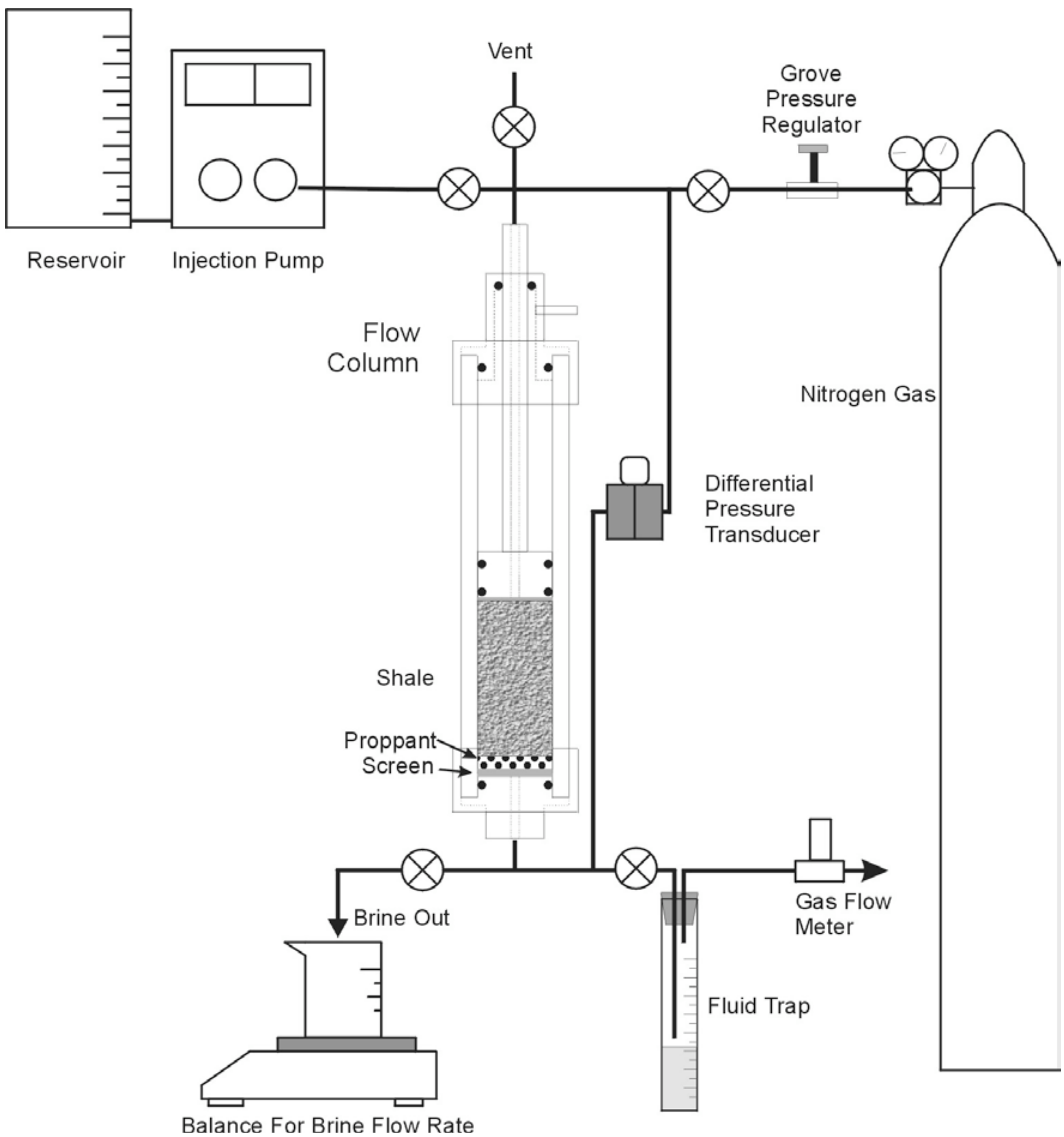


Figure 14
Equipment Flow Diagram for Flow Studies - Stim-Lab™



Appendix I

Capillary Suction Time Tests

Capillary suction time (CST) tests are performed using the Fann model 44000 CST timer. CST tests measure the retention of fluid by a slurry of the ground formation rock in the fluid to be evaluated. The slurry is placed in a funnel atop a chromatography paper. The timer measures the time for the fluid to be extracted from the slurry by adsorption into the chromatography paper. Sensors start the timer when the fluid reaches approximately 0.25" from the funnel and stop the timer at a distance of 1" from the funnel. Fluids that disperse clays in the formation slurry form a clay colloid (mud), which resists extraction of the fluid, and give long CST times. Fluids that do not form a colloid are easily extracted and give short CST times. A correction is made in the measurement for the viscosity of the fluid and fluid/paper interactions for comparison of fluids with the same core material. This is done by measuring the time for the fluid alone without formation material to be adsorbed. This is called the blank time. Three CST times are measured for each rock/fluid combination and averaged. The data is presented as a ratio of the CST time minus the blank time divided by the blank time. High CST ratios indicate increased colloid formation and more potential formation damage. Value differences for CST ratio of less than about 0.5 are usually within experimental error and are not considered significant. Magnitude of the value for CST ratio will vary depending on grain size distribution, and the amount of clay and silt within the rock sample. Therefore, the values cannot be compared between rock samples except in relative terms to two control fluids. These are usually a high saline solution, such as 6% KCl, and freshwater.

Formation samples are prepared by crushing the rock to less than 70 mesh in size. The crushed rock is then mixed with the fluid to be tested at a ratio of 1 gram to 20 ml. The slurry is mixed rapidly for 15 -20 minutes. A 5 ml portion of the slurry is extracted and placed into the CST funnel with a new sheet of paper. The CST time is recorded and the measurement made two more times with fresh paper for each measurement. The times are averaged. A blank time is measured for each fluid in triplicate for each box of chromatography paper. The blank time is then used in the calculation of the CST ratio.

Flow Back Additive Studies

Barnett shale matrix permeability is too low to allow for flow studies. Primary production is believed to be from natural fractures. While fracture flow studies are possible, more core material is required to conduct these type studies than what was available. Therefore, flow studies were conducted using ground material sieved to 35 –120 mesh size range and packed into a confined flow chamber as shown in **Figure 13**. To allow for sufficient comparison tests with the various products, core samples from the Southern Well were combined to give a composite sample. Table 1 gives the samples that were combined. All samples were from the Lower Barnett. Additional samples from the A and B sub zones of the Lower Barnett from the Northern Well were combined as well as samples from the C, D and E sub zones. These were used following the initial screening with the Northern Well samples to verify the applicability of the best performing products to shale samples from a different area. The material from each sample was ground with a mortar and pestle and placed on a sieve stack of a 35 mesh sieve over a 120 mesh sieve over a pan. Material that would not pass through the 35 mesh sieve was returned to the mortar and reduced further. Material passing the 120 mesh sieve was retained and used for x-ray diffraction analysis.

Packing was conducted by filling _ of the chamber with 50,000 ppm (Cl^-) brine. The brine was selected based on typical produced water used in water fracs in the Barnett. The brine formulation is given in Table 2. In the bottom of the chamber was a 100 mesh stainless steel screen. 5 grams of 80-120 mesh sand was added and the chamber tapped to settle the sand. On top of the sand was added 30 grams of the Barnett shale mixture. The chamber was again tapped to settle the ground shale. The plunger was placed in the chamber and the top cap affixed. The piston was then pressured to 50 psi to confine the pack. The pack was then allowed to set overnight to hydrate the shale and stabilize.

The flow chamber was plumbed to the flow system diagramed in **Figure 14.** The pack was flooded with the 50,000 ppm brine from the top downward at 10 ml/min until the differential pressure, as measured by the differential pressure transducer, stabilized indicating that the pack was settled and stabilized. An electronic balance at the exit was used to verify flow rate.

Brine flow was stopped and the vent valve at the top of the pack was opened and the brine allowed to drain from the pack into a trap. Methane gas was then flooded through the pack at constant pressure of 3 psi and the gas flow rate monitored with a mass flow meter on the other side of the water trap. Gas flow was conducted until the flow rate at 3 psi was constant. Gas flow was then stopped. The gas permeability was then calculated and the amount of water produced measured.

The brine and gas flow were then repeated with the flow-back enhancement additive placed into the brine solution at the supplier's recommended concentration. The amount of water produced with gas flow and the gas permeability following the additive treatment were measured and compared to gas displacement without additive.

Finally the flow chamber was opened and the sand/shale pack extruded into a tared weigh boat. The weight of the material was measured. The pack material was then placed in a 200 ºF oven to dry. The dry weight was then measured. The weight difference gave the amount of water remaining in the pack. These weights were then compared between products and a control where no treatment was performed.

Figure 13
Confinement Cell Used For Flow Studies - Stim-Lab^tm^

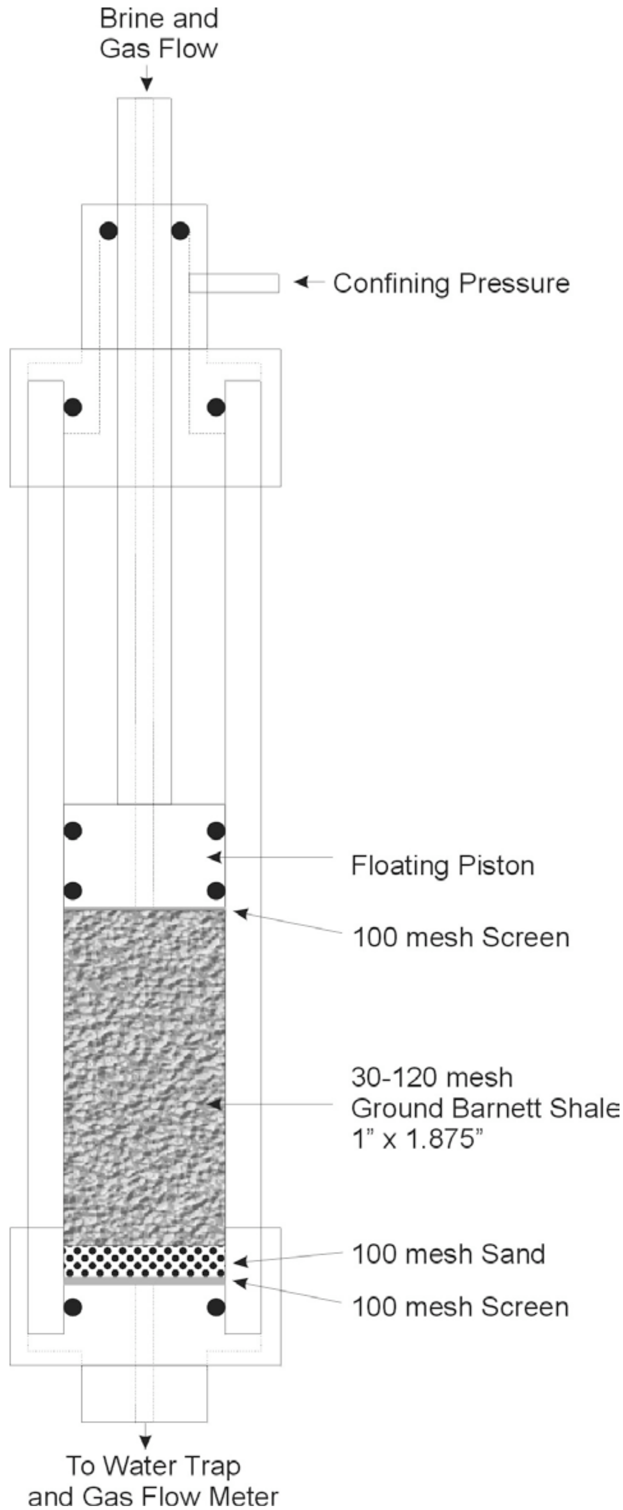
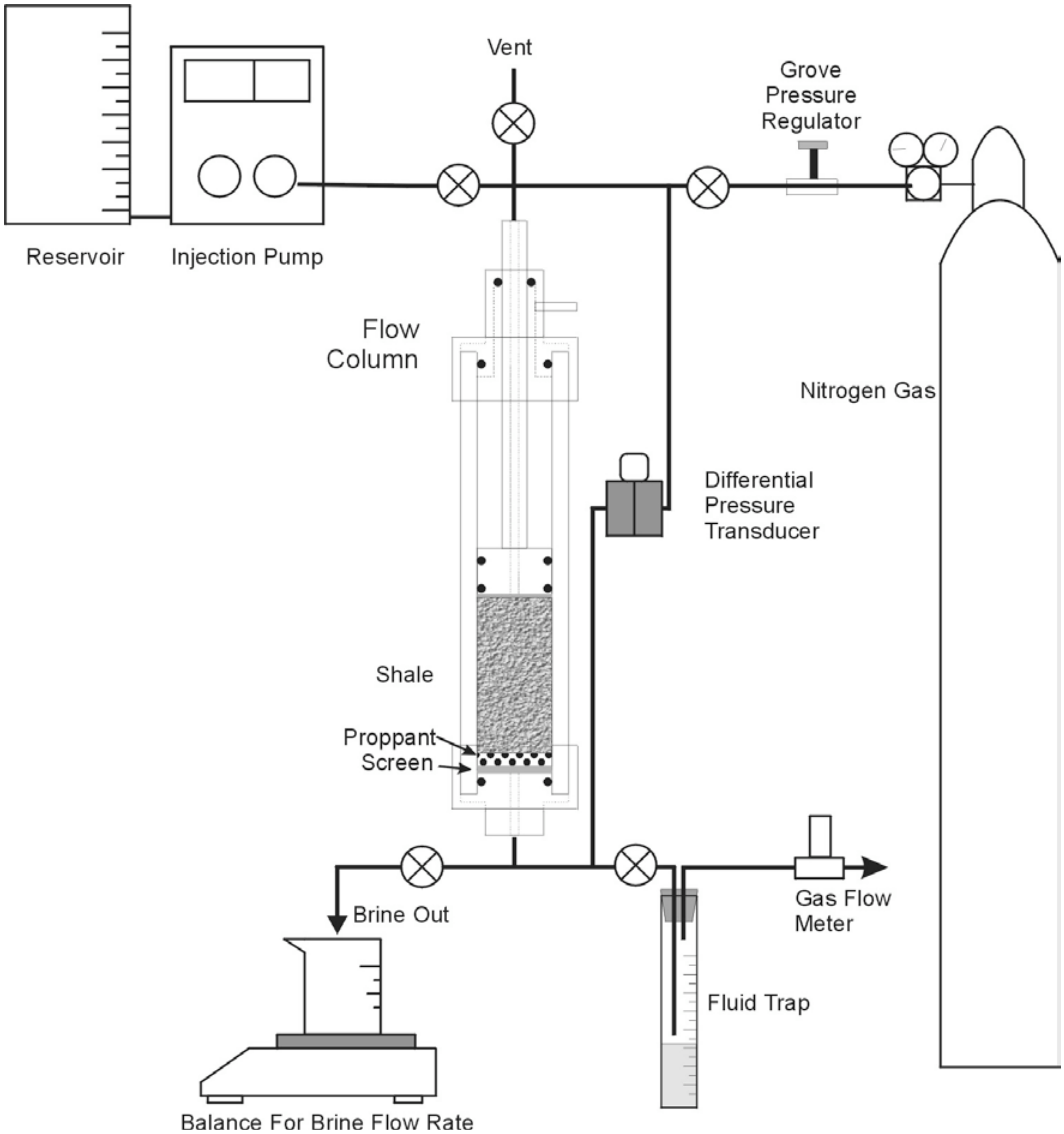


Figure 14
Equipment Flow Diagram for Flow Studies - Stim-Lab^tm^



Developing Methods to Identify Unstimulated and/or Ineffectively Stimulated Reservoirs Resulting from Multi-Stage Hydraulic Fracture Treatments

During the Period 05/15/2002 to 11/30/2002

By

Gerald W. Merriam, Walter K. Sawyer, P.E., and Joseph H. Frantz, Jr., P.E.
Schlumberger Holditch – Reservoir Technologies

November 2002

Work Performed Under Prime Award No. DE-FC26-00NT41025
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Pennsylvania State University
University Park, Pennsylvania

Gerald W. Merriam
Senior Engineer

Walter K. Sawyer, P.E.
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Reservoir Simulation

Joseph H. Frantz, Jr., PE
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Division Manager

November 2002

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DISCLAIMER

1 Executive Summary

This report summarizes an evaluation performed by Schlumberger Data and Consulting Services (DCS) and Equitable Production Company (Equitable) regarding the area of reservoir remediation, characterization, and operations. Several groups of Equitable's Appalachian Basin wells in West Virginia (WV) and Kentucky (KY) were used in the study. The objective of this project was to identify unstimulated and/or ineffectively stimulated reservoirs in stripper wells treated with multi-stage hydraulic fracture treatments. Multi-stage involves pumping two to four hydraulic treatments in a well with many low-permeability formations perforated and open to each treatment. Multi-stage treatments are common in the Appalachian Basin **(Fig. 1)** and in many low-permeability wells across the U.S., because multiple sand, shale, and carbonate reservoirs often occur over a thick, stratigraphic interval. Based on our experience, it is unlikely that all perforated intervals are treated effectively when performing multi-stage stimulation treatments due to the large gross interval open in the wellbore.[1]

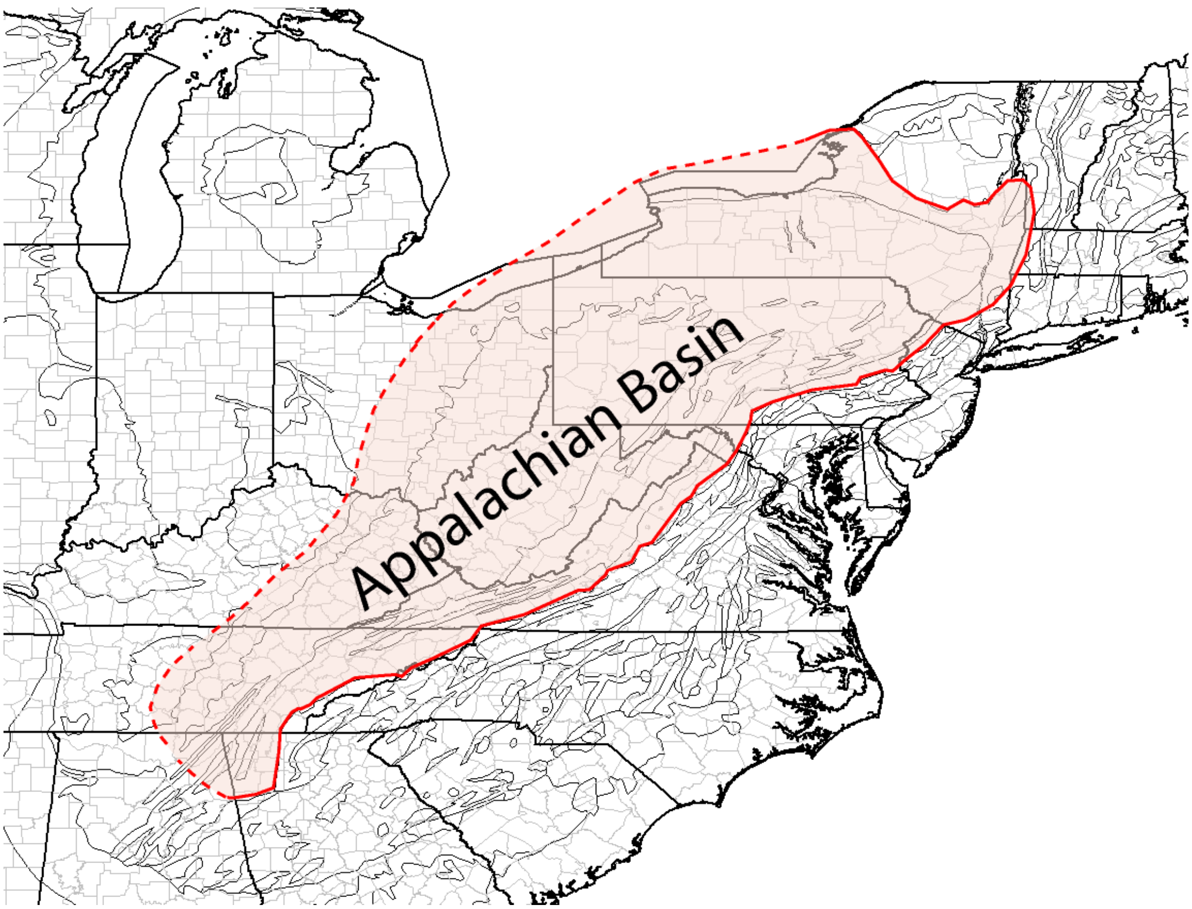

Fig. 1 – Appalachian Basin map.

Using existing data and by collecting new downhole diagnostic data, we determined the extent of stimulation in a perforated interval in a study well provided by Equitable Production Company (EPC). The well is located in Pike County, Kentucky. The downhole diagnostic data includes memory production log (MPL), isolation tests, injection/falloff tests, hydraulic fracture data analysis, and production data analysis. We determined the interval was ineffectively stimulated because it was non-productive, but showed good log responses. An injection/falloff test was performed and showed the perforations were open, the reservoir pressure was low, and there was a fracture in the zone. A decision was made to restimulate the interval since the pumping equipment was on-site and it would therefore be a minimal cost. The well was thus restimulated with a nitrogen treatment since the well was originally completed using nitrogen stimulations. A history match of post-production indicated that the restimulation probably created a wider fracture with the same initial length. This slightly improved performance. It is uncertain how long this fracture will remain open or what width it may retain due to the lack of proppant. Many operators in the Appalachian Basin have switched to this method as the fluid of choice over the past ten years.

This well was a poor restimulation candidate due to the low reservoir pressure (190 psi) and the existence of a fracture (100 feet length and .00045 inches wide). The restimulation did increase the width of the fracture from 0.00045 to 0.00605 inches, but did not increase the length of the fracture. The well production improved from too small to measure to 6 Mscf/D, but the production will continue to decline and the zone has an estimated recovery of 14 MMscf. At an approximate cost of $30,000 this restimulation was uneconomic.

An evaluation methodology was developed for use by any Appalachian Basin operator to determine which formations were ineffectively stimulated with past treatments. We anticipate that this methodology will also be useful for other operators throughout the United States where multi-stage treatments are pumped.

Ultimately, we believe that this work could result in a paradigm shift for operators. If they understand that certain formations were not stimulated and/or not effectively stimulated, they will restimulate these formations in existing stripper wells. This project could result in substantial new production from stripper wells for Appalachian Basin operators. Given the currently high value of natural gas (>$4/Mscf), even very low flow rates (5 Mscf/D) resulting from restimulations may be economic. Operators may also change their field stimulation procedures in new wells to treat all formations more effectively.

The potential benefit to the Appalachian Basin stripper well community may be significant. We believe that about 75% of the 66,000 stripper wells in Pennsylvania (PA), WV, and KY were stimulated with multi-stage treatments. We estimate that 50% of these (about 25,000 stripper wells) may have restimulation potential, but only half of them (12,500 wells) may be in sound mechanical condition for restimulation. If the restimulation treatments result in a 5 to 10 Mscf/D production increases per well, the overall significance to the Appalachian Basin is large. We estimate a potential impact to the Appalachian Basin of 94 MMscf/D or 34 Bscf/year if all the mechanically sound stripper wells in PA, WV, and KY were restimulated. This represents a 20% increase in the current total stripper well gas production level in these 3 states. This could represent $137 million in new revenue.

While the cost to run a MPL, isolate a zone, perform an injection/falloff test, fracture stimulate the zone, and analyze the data is dependent on several factors such as size of treatment, depth of well, equipment requirements, etc. it is estimated that a typical Appalachian operation would cost $25,000. Assuming an incremental increase of 10 Mscf/D, a royalty of 12.5%, and a gas price of $4/Mscf it would have a payout time of less than two years.

2 Introduction

Most wells in the Appalachian Basin (and throughout the United States) are stimulated with multiple hydraulic fracture treatments. This is necessary because multiple low permeability reservoirs often occur across a thick, stratigraphic interval. In the Appalachian Basin, the formations include the Devonian Shale, the Upper Devonian sands, and the Mississippian sands and carbonates. It is not uncommon to perform two to four hydraulic fracture treatments over a gross interval greater than 1,000 ft. The number of perforated intervals is even more extensive ranging from four to 10 in a typical Appalachian Basin well. This means that several formations are open at the same time in each of the stimulation treatments.

The problem with current multi-stage practices is the uncertainty in which intervals were effectively stimulated, **Fig. 2**. Most operators have several stimulation treatments performed in one day to reduce the cost per stimulation. It is unknown which perforations accepted the treatment and the overall fracture geometry. After the treatments, it is rare for an operator to perform any analysis to determine how many of the formations were stimulated, let alone evaluate the stimulation effectiveness in the intervals that accepted the treatment.

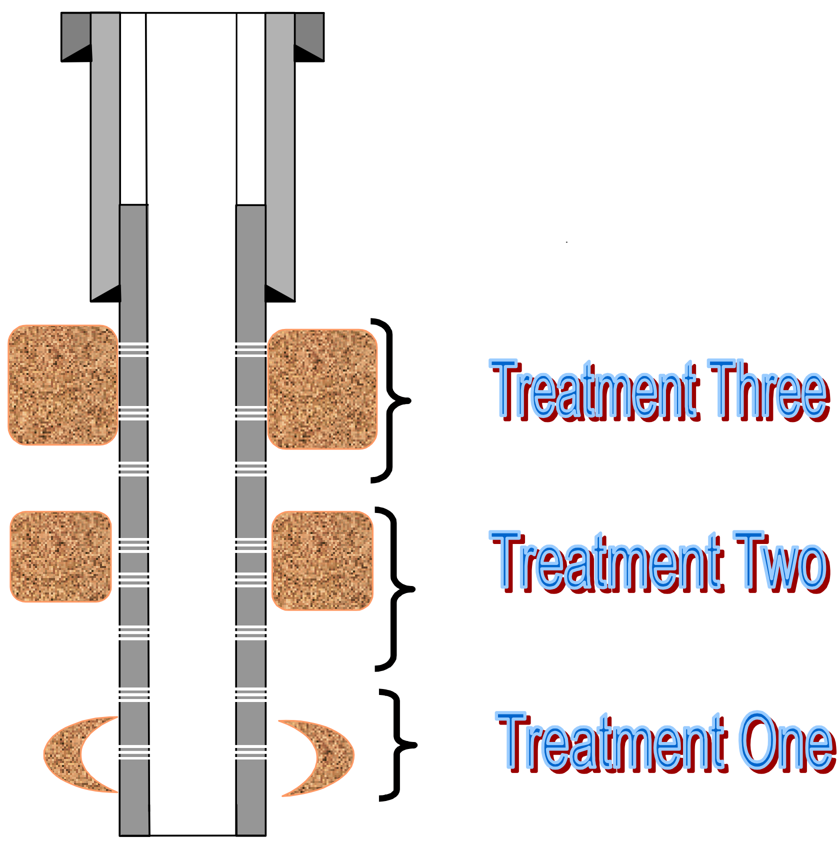

Fig. 2 – Multi-stage treatments can result in uncertain stimulation effectiveness.

Other problems exist with current multi-stage treatments. Many operators use the ball and baffle method as a means to isolate each new treatment interval in a multi-stage treatment when pumping nitrogen-foam and proppant. When they are ready to perform the next treatment a frac ball is dropped and then pumped downhole usually with the acid to be used on the next stage. This ball seats on a baffle, present in the casing, and isolates the zone. It is difficult to predict the actual required displacement due to the compressibility of the foam fluids ahead of the acid and is suspected that many of the treatments are overdisplaced. To our knowledge in the Appalachian Basin, it would be rare for an operator to perform a post-fracture test to evaluate the near-wellbore fracture conductivity after a treatment has been possibly overdisplaced.

Due to low reservoir pressures and concerns of water sensitivity, many wells especially completed in the Devonian Shale are fractured stimulated using straight nitrogen without proppant or liquids. These nitrogen-only treatments also result in an uncertain fracture conductivity, fracture half-length, fracture height, and overall stimulation effectiveness. The industry is uncertain which intervals are treated when multiple intervals are open during a nitrogen treatment. The resulting fracture geometry from nitrogen stimulation treatments is one of the largest unknowns in the industry. Previous GRI research has shown that thin, low viscosity fluids may stay in zone. Nitrogen is a low viscosity gas; therefore it may indeed stay in zone, and not treat many zones vertically in the wellbore. If one perforated interval accepts all or most of the treatment, the other perforated intervals may remain untreated or be ineffectively treated.

Finally, previous industry research has shown that stimulating naturally-fractured, low permeability formations can result in highly variable hydraulic fracture geometries[2,3]. The Appalachian Basin stripper wells fall into this category since they are completed in naturally-fractured, low permeability reservoirs. For example, an interval that is very naturally-fractured may take all the treatment. The perforation scheme and breakdown may also affect where the treatment enters. Additionally, treatments may not grow vertically for extended distances due to complex natural fractures, i.e., the growth of hydraulic fracture may stop at lithology changes where natural fractures terminate[3]. There is a concern over which intervals accept the treatment and the resulting hydraulic fracture geometry.

A literature search was initiated to determine what if any studies were done on the above subjects. Searches were performed on selected terms: multistage fracturing, nitrogen fracturing, field testing, restimulation, testing. Two hundred sixty ± abstracts, reports, or papers were reviewed. Seventy-seven of the more relevant abstracts, reports, or papers are listed in Appendix A. Twelve of the records had some bearing on this study and are listed first in Appendix A.

Equitable had previously run over 40 memory production logs. Memory production logs are run on slick lines with the logging data stored in downhole memory and played back on location after tools are retrieved from the well. This produces a log equal to that of surface readout with less equipment and manpower. **Table 1** shows the thirty-one memory production logs reviewed to determine what zones are and are not producing. These were compared to the openhole logs in an attempt to determine if nonproductive zones should have been productive if effectively stimulated.

Table 1
Summary of Memory Production Log Analysis Results

		Measured Flow	Percentage of Gas Production per Zone							
Well Name	Completion Zones	During P/L, Mscf/D	Ravenscliff	Maxton	Big Lime	Weir	Berea	Gordon	Upper Shale	Lower Shale
Ritter #348	G/B, BL, Rav	234	11		66		23 (G/B)			
Pocahontas/Carnegie #2	LDS, UDS, BL	92			40				20	40
Pardee Land #93	LDS, UDS, B/W, BL	380			12	3	70		10	5
Hinchman #B-2	LDS, B/G, W/BL, Max	120		20	35	0	0	35	10	0
Ritter #235	Rav,Max,G,UDS,LDS	85	80	0				10	0	10
Elk Creek Coal #36	BL,B,UDS,LDS	157			35		35		20	10
Island Creek #D-86	W/BL,UDS/G/B,LDS	275			80	5	0	0	12	3
Elk Creek #42	BL,B,UDS,LDS	203			20		23		37	20
Coal & Crane B-26	BL,B,UDS,LDS	66			20		30		47	3
David Francis Trust #4	BL,B,UDS,LDS	80			0		40		52	8
David Francis Trust #5	BL,B,UDS,LDS	68			20		20		55	5
Thacker Land A-7	BL,W/B,UDS,LDS	80			20	0	0		70	10
Island Creek #D-29	BL,B/UDS,LDS	155			60		10(UDS)		*	30
EPC Hall W.D. KF 4427	B/W,B/UDS,LDS	108				15			77	8
EPC John Godsey #1 KF 918	B/UDS,LDS	77					100(UDS)		*	0
Gibson E 2KL 1446	BL,B/UDS,LDS	71			20		0		30	50
Harve Johnson KF 4448	BL,B/UDS,LDS	68			18				58	24
W.D. Hall KF 1604	W,B/UDS,LDS	50				15	0		75	10
Rouge Steel #2	B/LDS	89					60			40
Ford Motor 1-094	BL,B/UDS,LDS	190			10		80(UDS)		*	10
Smith Carrs Fork 2-1	BL,W/B/UDS,LDS	82			10	0	70(UDS)		*	20
Hatcher 4-105	BL,UDS/B,LDS	57			0				50	50
Hatcher 4-060	BL/B,B/UDS,LDS	15			30				65	5
Republic Steel 2-108	Max,B/UDS,LDS	Due to large volume of fluid was unable to acquire accurate interpretation								
Colony C&C 2-101R	BL,B/UDS,LDS	130			10		50(UDS)		*	40
Chesapeake Mineral 2-051	BL,B/UDS,LDS	100			0		70(UDS)		*	30
Emperor Coal 1-285	BL,B/UDS,LDS	72			55		25(UDS)		*	20
Ford Motor 165	B/UDS,LDS	40					80(UDS)		*	20
Chesapeake Mineral B-39	BL,B/UDS,LDS	25			80		10(UDS)		*	10
Republic Steel #79	B/UDS,LDS	38					60(UDS)		*	40
S. Coleman 2-018	Max,BL,B/UDS,LDS	220		25	10		42(UDS)		*	23

* In most of the Kentucky wells, the Berea is completed with the Upper Devonian Shale.

LDS – Lower Devonian Shale
UDS – Upper Devonian Shale
G – Gordon
B – Berea
W – Weir
BL – Big Lime
Max – Maxton
Rav – Ravenscliff

This review resulted in 10 of the 31 wells containing zones that were either not producing or producing less than the openhole logs would indicate. Thus, these 10 wells are possible candidates for restimulations as shown in **Table 2**.

Table 2
Recompletion Candidates

Well Name	Recompletion Zone	Comments
Pocahontas/Carnegie #2	Upper Devonian Shale Lower Devonian Shale	Several zones in shale not producing
Hinchman B-2	Berea, Weir, Big Lime	Zones not producing
Island Creek D-86	Berea	Very little production
Thacker Land A-7	Berea	Not producing
Gibson E 2KL 1446	Upper Devonian Shale	Lower perforations in Upper Devonian Shale not producing
Harve Johnson KF 4448	Berea	Not producing
Smith Carrs Fork 2-1	Weir	Not producing
Hatcher 4-105	Big Lime	Dolomite zone not producing after acid treatment
Hatcher 4-060	Big Lime	Dolomite zone acidized producing little gas/oil
Ford Motor 165	Upper Berea	Not producing

Most of the wells were stimulated using nitrogen without proppant. Fracture modeling was performed to determined theoretical fracture width and length. This modeling was performed using the MFrac™ software by Meyer & Associates, Inc.

A simulation model using SHALGEGAS™ has been built to evaluate what type of nitrogen injection test can be used to determine if an interval has been fracture stimulated. The model is set up to simulate both injection/falloff tests and gas production for nitrogen fractures of various aperture widths.

3 Conclusions

- Memory production logs are useful in determining the relative amount of gas flowing from each interval.
- Comparison of these production logs versus the openhole log can determine what zones are producing less than expected.
- Modeling of nitrogen fracture treatments indicates very narrow and short fracture lengths, especially if multiple-fractures are developed.
- Simulation using SHALEGAS™ indicates that even the small fracture widths created by using nitrogen fracturing can be detected using injection/falloff testing.
- Field injection/falloff testing will be required to determine if these non-productive, or lower than expected productive zones, were effectively stimulated.
- Most of the wells had fluid levels in or above the Lower Devonian Shale.
- This fluid was negatively affecting production as demonstrated by the production increases in many of the wells after swabbing to remove the fluid.
- Quicker, lower cost and more efficient methods to evaluate the effectiveness of stimulation are needed.

4 Recommendations

The following methodology should be used to identify unstimulated or ineffectively stimulated reservoirs in wells treated with multi-stage hydraulic fracture treatments:

1. Run Memory production logs on wells suspected of having zones unstimulated or ineffectively stimulated.

2. Evaluate production log and compare to the openhole logs. Estimate porosity-thickness product for each zone

3. Select underperforming intervals.

4. Isolate interval and perform an injection/falloff test to determine if a fracture exists.

5. History match data with simulator to estimate permeability-thickness product, reservoir pressure, skin factor or fracture width and fracture length.

6. Forecast production using simulator results.

7. Restimulate zones that can be economically justified.

8. Production test restimulated interval(s).

9. Analyze results.

Even when nitrogen treatments are used, procedures such as swabbing or soaping and then blowing the well should be performed during a well's life to remove any fluids above the Lower Devonian Shale perforations.

Additional studies should be performed to developed quicker, lower cost and more efficient methods to evaluate the effectiveness of stimulation.

5 Discussion Of Results

5.1 Literature Search

A literature search was performed to determine what if any studies were done on this subject. Searches were performed on selected terms: multistage fracturing, nitrogen fracturing, field testing, restimulation, testing. Two hundred sixty ± abstracts, reports, or papers were reviewed. Seventy-seven of the more relevant abstracts, reports, or papers are listed in Appendix A. Twelve of the records had some bearing on this study.[1,2,3,4,5,6,7,8,9,10,11,12] The literature search confirmed that no previous study had been done for the specific purpose of this report.

5.2 Process procedure

To determine if a zone has been stimulated effectively we evaluated the following:

1. Memory production log to determine what zones are actually producing and their rates.

2. Openhole logs to determine which zones should have been productive if stimulated based on typical evaluation of net pay, porosity, and hydrocarbon saturations.

3. Predicted hydraulic fracture geometry that is depended on treatment.

4. Simulation of injection/falloff test to determine if an actual injection/falloff test would indicate if a zone had been effectively stimulated or not.

5. Actual injection/falloff test

Memory production logs (MPL) were run to determine the zones that were producing and their approximate production rates. Openhole logs were evaluated and compared to the MPL. To determine if a fracture had been created an injection/falloff test would be performed. To evaluate this injection/falloff test, the relative fracture geometry would need to be known. Since the majority of the zones were completed using nitrogen fracture stimulation, it was necessary to model this type of treatment to determine theoretical fracture width and length. Then a simulation of a nitrogen injection/falloff test was performed using the width and length estimated in the fracture modeling. Finally an actual injection/falloff test was performed and analyzed in a field test candidate.

5.3 Memory Production Logging

The use of memory production logs to determine the quantity of gas being produced from perforated intervals appears to perform fairly well. The MPL uses the same downhole tools and sensors to acquire measurements as a normal production log operation. To configure the MPL, the internal surface readout telemetry cartridge is simply replaced with a memory module and battery. The downhole tools are conveyed in the borehole by slickline. Cost savings is due to reduced manpower (one person can run the unit versus two to three for a normal electric line with surface readout operation) and the smaller unit is much less likely to need any additional equipment such as a dozer to get on location. This makes it a fast, easy, and safer operation.

The normal tool string configuration is a battery pack, memory production logging adaptor, casing collar locator, gamma ray, gradiomanometer, pressure recorder, temperature sensor, and a fullbore flow meter. The MPL can clearly identify gas, water and/or oil entry points into the wellbore **Fig. 3**.

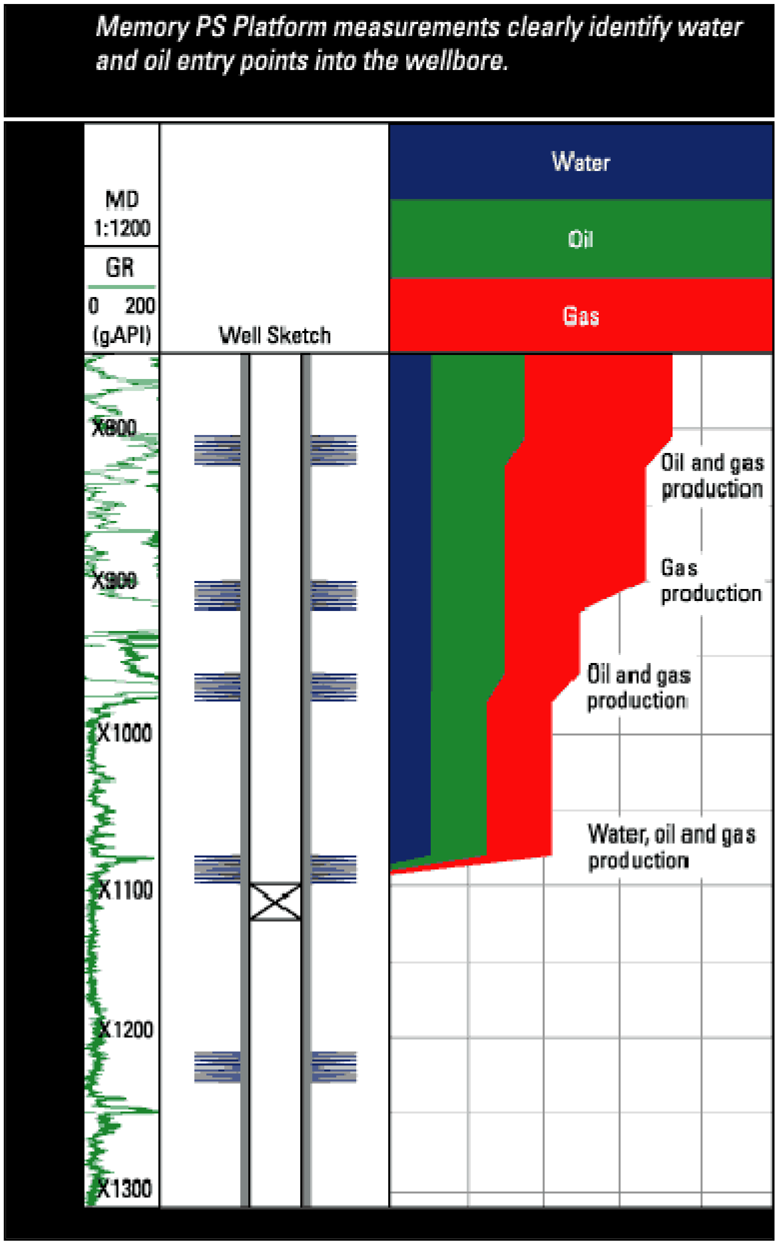

Fig. 3 – MPL clearly identifies gas, water and/or oil entry into the wellbore.

MPL's were run in 40 wells with 31 located in southern West Virginia and eastern Kentucky. Most wells were treated with 2 to 3 Nitrogen treatments. A typical treatment was performed using 600,000 to 800,000 scf of Nitrogen at rates of 60,000 to 80,000 scf/min. Usually a small amount of HCL acid (250 to 500 gallons) is pumped ahead of the nitrogen treatment to aid in the breakdown of the perforations. The biggest problem was most wells showed fluid levels in and even above the lower Devonian Shale perforated zones on the production log with the lower shale producing little if any in most of these wells. This was true even in the wells that the Berea and Devonian Shale were completed using only nitrogen fracture stimulation. Most of the wells had their fluid levels shot and were subsequently swabbed less than two weeks prior to running the MPL. **The production-logging candidates are shown in the Appendix B.**

Of the 31 logs reviewed and correlated with openhole logs, it was determined that 10 of the wells had recompletion candidate zones. Ninety percent of the wells had fluid (mostly salt water with a few wells having small amounts of oil with the salt water) above the bottom perforation in the well **Fig. 4**. Forty percent had fluid covering the lowest completed formation. The formations that had potential for recompletion were the Big Lime, Berea, Weir, Upper Devonian Shale, and Lower Devonian Shale.

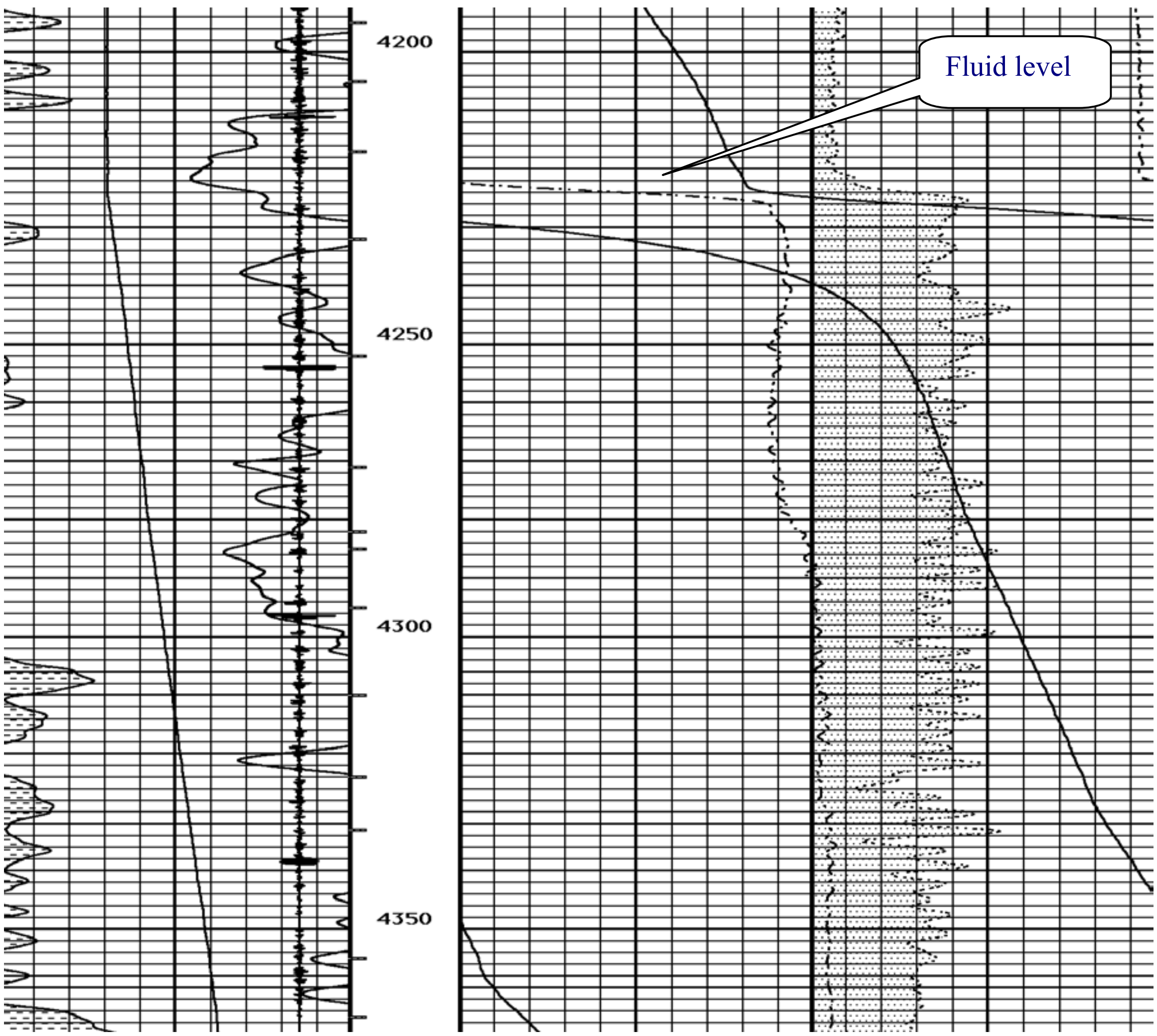

Fig. 4 – MPL showing fluid level in Lower Devonian Shale.

Equitable is in the process of running 33 additional memory production logs. They are running the logs based on the excellent information obtained in the original 31 MPL's. These logs will be evaluated to determine additional recompletion candidates.

5.4 Fracture Geometry

The Devonian Shale/Berea were typically completed by two-stage nitrogen fracture treatment in which each stage is perforated in four to ten intervals. To determine the theoretical fracture geometry for nitrogen fracture treatments two different models were designed using the Mfrac software. Both models assumed nitrogen fracture stimulations using 600,000 scf of nitrogen at treatment rates of 60,000 scf/min. The first model assumed that each interval (ten intervals were selected) was treated and each developed their own fracture. This model indicated frac widths of 0.013 – 0.015 inches with an average fracture length of approximately 55 ft, **Fig. 5.** The second model assumed all the intervals were treated, but only one fracture was formed. This model indicated a fracture width of 0.055 inches with a fracture length of approximately 95 ft, **Fig. 6.**

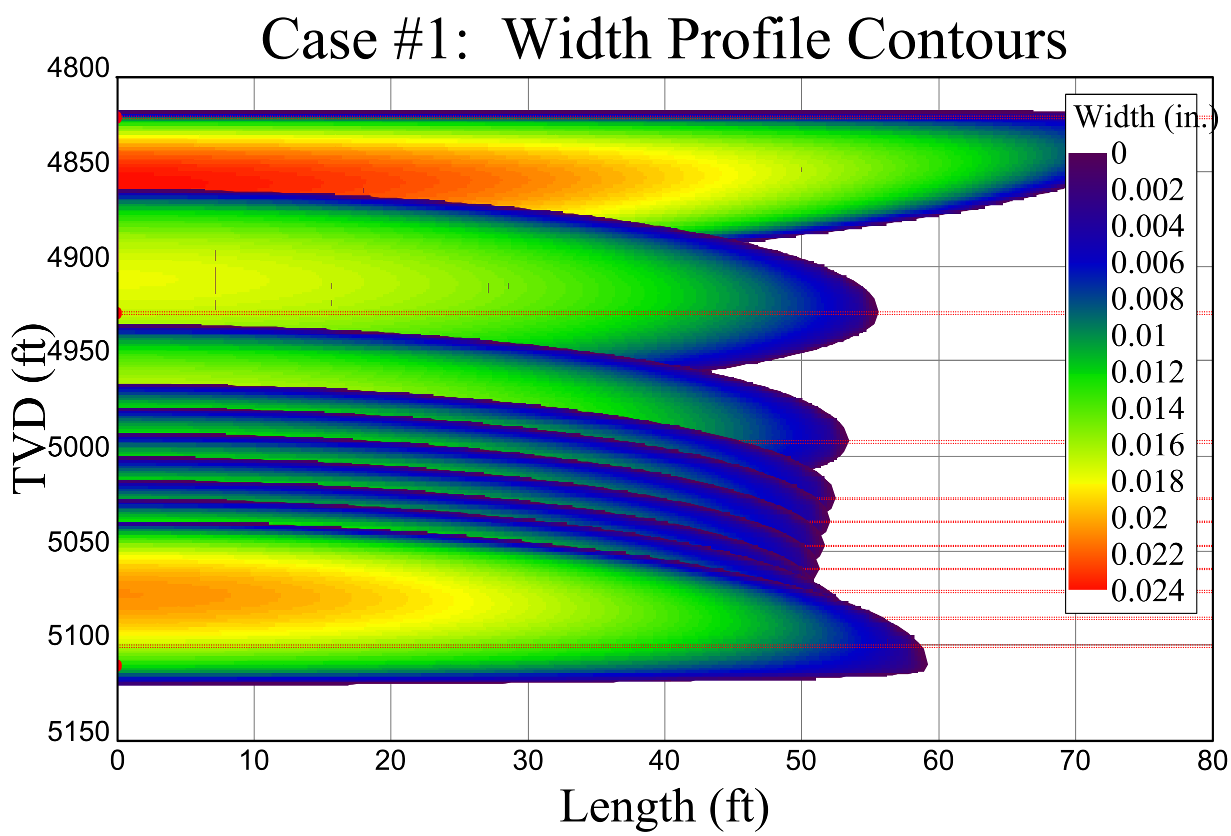

Fig. 5 – Multiple fractures created.

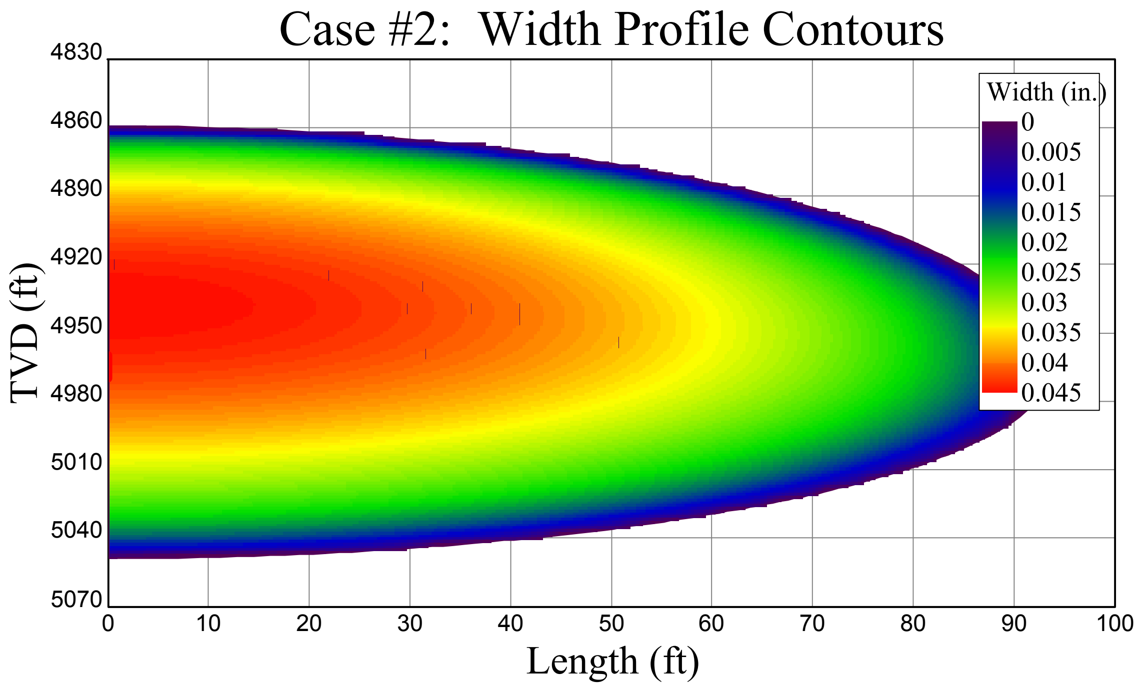

Fig. 6 – One fracture created.

While it would be very difficult to determine how many fractures are created during a treatment, it can be reasonably estimated that 2 to 3 fractures may be created, this depends on the existence of fracture barriers, number of perforations that break down, distance between perforations, nitrogen injection rate, deviation of the wellbore, angle of hydraulic fracture, etc.

5.5 Test Well

Ford Motor #165 was selected by DCS and EPC as a candidate for recompletion based on the production log and open hole logs. This well was completed in 1997 using a two-stage nitrogen fracture stimulation without proppant. The first stage was in the Lower Devonian Shale and the second stage was in the Upper Devonian Shale and Berea. The Lower Devonian Shale was perforated from 3,973 ft to 4,365 ft for a total of 24 holes. It was then nitrogen fracture stimulated using 600,000 scf nitrogen at a rate of 60,000 scf/min. 350 gallons of 8.2% HCL-Fe acid was dumped prior to the treatment to assist in breaking down the perforations. 27 perf balls were dropped during the treatment and slight ball action (pressure increases) was noted. The Upper Devonian Shale and Berea was perforated from 3,325 ft to 3,639 ft for a total of 23 holes. It was stimulated using 850,000 scf nitrogen at 60,000 scf/min. Four hundred gallons of 8.2% HCL-Fe acid were used. Twenty-six perf balls were dropped and good ball action was noted. The well was flowed back and had an openflow gas test of 592 Mscf/D.

The well had been producing since completion in 1997 and was producing 39 Mscf/D prior to running the MPL on April 2, 2001. The well was swabbed five days before the MPL with an initial fluid level at 4,050 ft. Almost the entire Lower Devonian Shale was covered with water. Six bbls of salt water were recovered during the swabbing. The production log indicated that the Upper Berea was not producing, **Fig. 7.** The openhole logs showed the zone to be 21 ft thick and have approximately 5% to 6% porosity and had indication of gas inflow on both the temperature and audio logs.

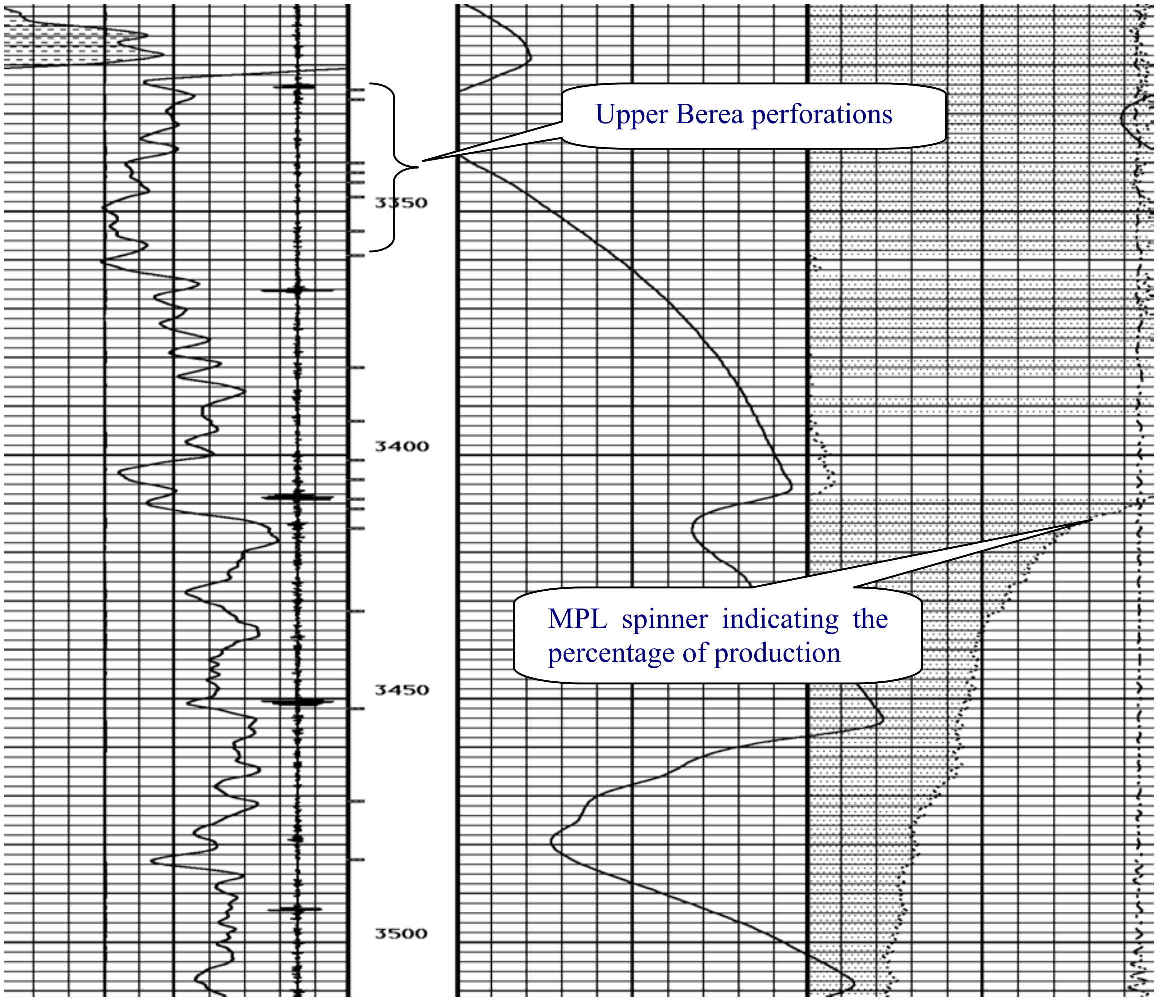

Fig. 7 – Ford Motor Company #165 MPL section through Berea.

5.6 Injection/Falloff Test Simulation

Part of our study involved a theoretical simulation evaluation to determine if a thin fracture created during a nitrogen stimulation treatment could be detected using an injection/falloff test using nitrogen. The simulation model using SHALEGAS™ was calibrated using the test well data. We assumed an openhole log porosity of 6%, net pay of 21 feet, an estimated original reservoir pressure of 745 psi and estimated reservoir permeability of 0.01 md. Sensitivities were run to simulate injection/falloff tests and gas production for various fracture aperture widths of no fracture (0 inches) up to widths of 0.005 inches. These simulation runs indicated that we would be able to determine if a fracture had been created if its width was at least 0.0003 inches, **Fig. 8**. The steep slope lines on the left side of the plot marked injection is the simulation of the injection phase of the test assuming a nitrogen injection rate of 1000 scf/min with fracture widths of 0 to 0.10 inches. The curved lines to the right of the injection phase are the simulated falloff pressure profile after injection ceases based on the fracture widths stated above. As shown in **Fig. 8** the falloff of the pressure should be much greater as the assumed fracture width (conductivity) is increased.

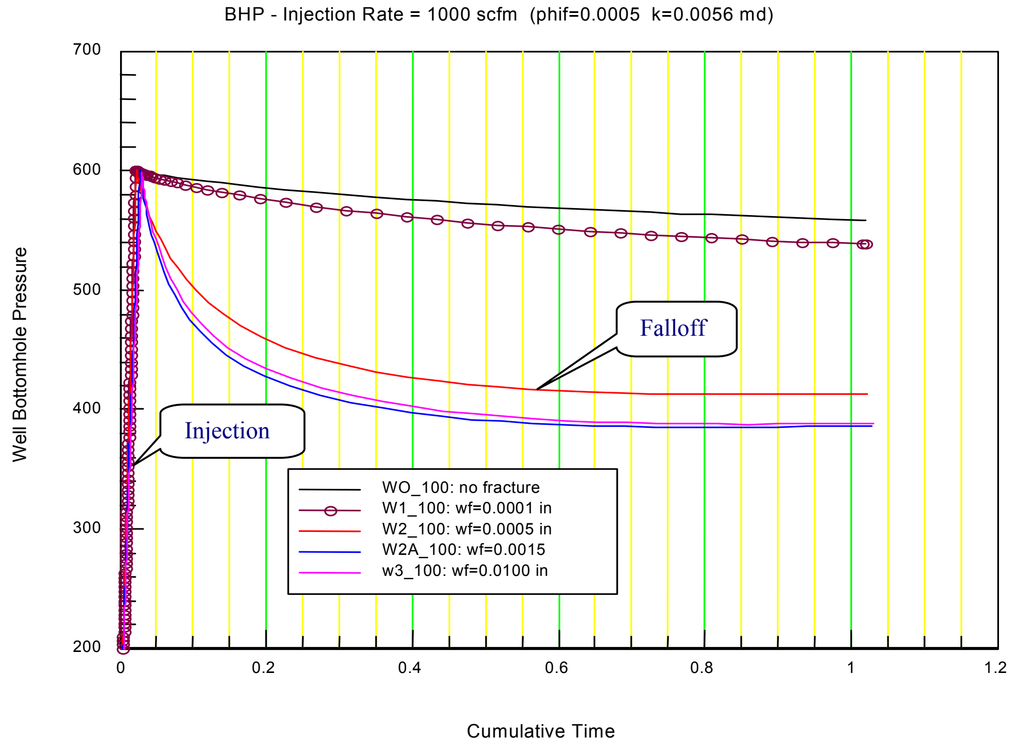

Fig. 8 – Simulation of injection/falloff test in Upper Berea.

5.7 Injection/Falloff Test

The testing of Ford Motor Company #165 well was initiated on July 17, 2002. Our plans called for performing an injection/falloff test with nitrogen to determine if a fracture existed in the Upper Berea. The well had been producing 30 Mscf/D into the pipeline from the Devonian Shale and Berea. The well was opened to the atmosphere and a gas test of 59 Mscf/D was taken. As stated above, the Upper Berea appeared not to be producing as per the memory production log ran on April 2, 2001. To perform the injection/falloff test and possible recompletion, tubing with a retrievable bridge plug and packer were run in the well to isolate the Upper Berea, **Fig. 9**. Once the bridge plug and packer were set, a gas test was taken with it being too small to measure. The well was put back in line overnight. The meter indicated that there was zero gas flow from the Upper Berea. The well was then shut in over the weekend.

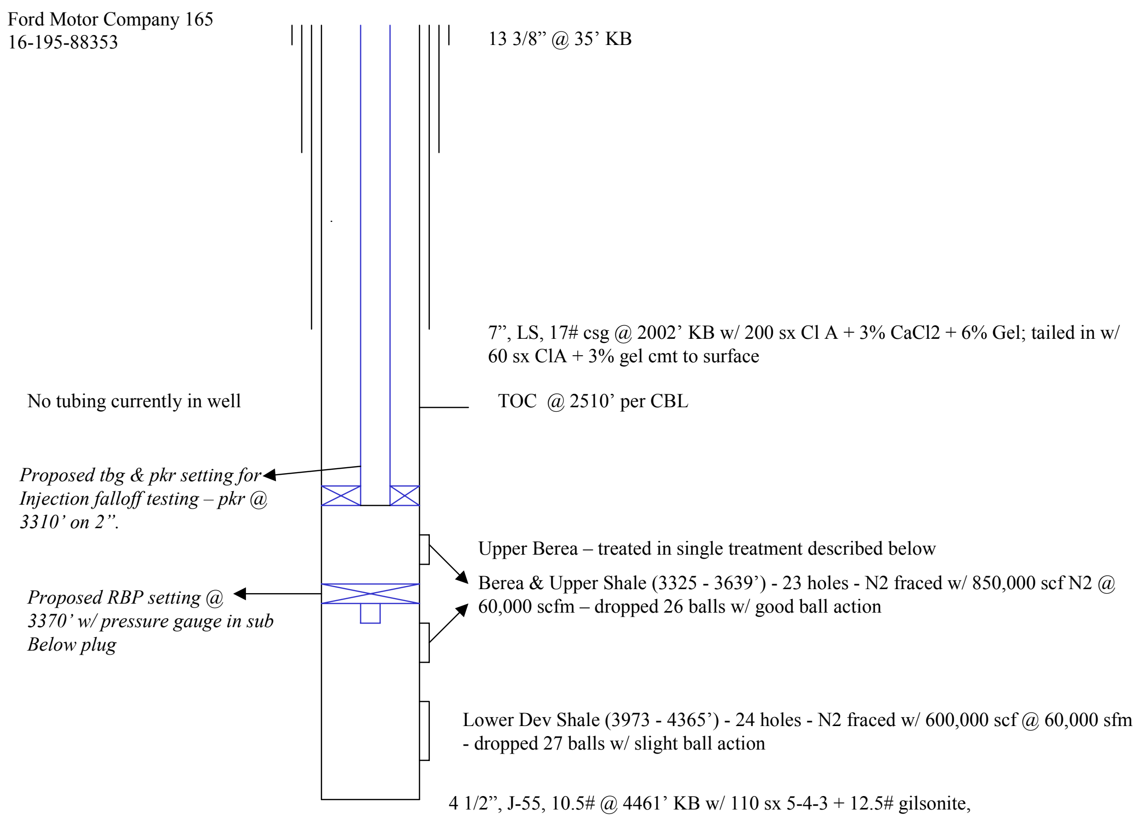

Fig. 9 – Ford Motor Company #165 prepared for injection/falloff test.

After the approximate 2 1/2 days of shutin, the well had a surface pressure of 80 psi. A pressure gauge on slick line was run in the tubing just above a seating nipple as shown in **Fig. 10.** An injection test was performed by pumping 6,500 scf of nitrogen at an average rate of 970 scf/D. Final injection pressure at the surface was 549 psi. The pressure gauge was lowered into the seating nipple to isolate the Upper Berea to record the pressure falloff. Pressure was increased to 769 psi on top of the pressure gauge to maintain a seal at the seating nipple. Bottomhole pressures were recorded during both the injection and falloff tests as shown in **Fig. 11**.

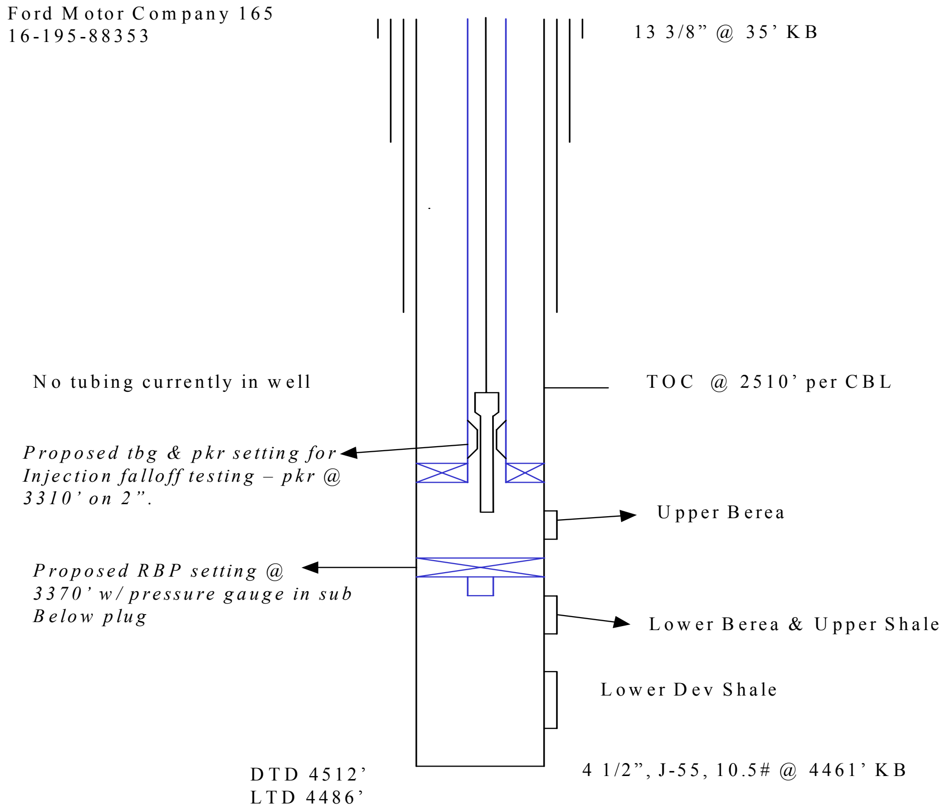

Fig. 10 – Ford Motor Company #165 well schematic during injection/falloff test.

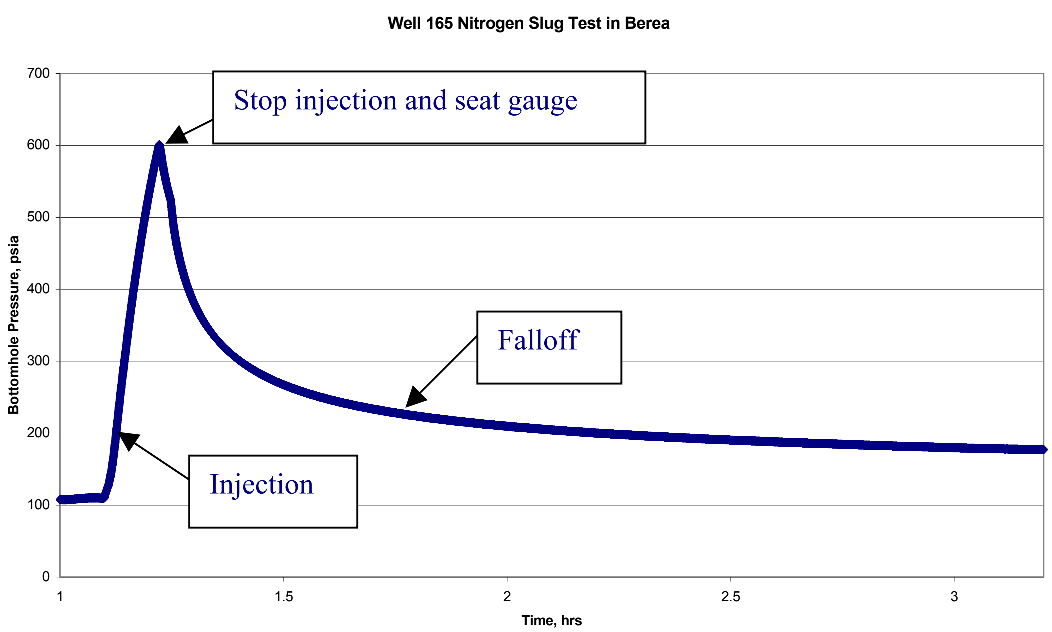

Fig. 11 – FMC #165 injection/falloff test bottomhole pressure.

Even though the injection/falloff data indicated a fracture and low reservoir pressure it was decided to restimulate the Upper Berea. The restimulation was performed by pumping 289 Mscf of nitrogen at an average rate of 20 Mscf/min rate. Gas test after cleanup was 47 Mscf/D. The well was put back in line and the Upper Berea produced at gas rates of 19 Mscf/D and 8.4 Mscf/D after one and two days, respectively. The tubing, packer, and bridge plug were pulled from the well. The well was put back in line and after 30 days it appears that the Upper Berea was producing an incremental 6 Mscf/D.

5.8 History Match of Injection/Falloff Test and Production Data

A history match of the pressure data from the injection/falloff test and of the production data after the restimulation was performed using SHALEGAS™. SHALEGAS is a versatile three-dimensional, two-phase, dual-porosity reservoir simulator designed to model flow of gas only, or gas and water in fractured shales such as the New Albany Shales of the Illinois Basin and Antrim Shale of the Michigan Basin, as well as other unconventional gas reservoirs. This includes formations such as the Berea, which is considered an unconventional reservoir due to low permeability and natural fractures. SHALEGAS numerically models the processes that control the behavior of these complex natural gas reservoirs: Darcy flow and desorption of gas in the matrix (in a shale) and Darcy flow of gas and water in the natural fractures. SHALEGAS was designed to predict the performance of these reservoirs. It can be used to design and analyze injection/falloff tests and history match reservoir performance.

The Upper Berea is probably a dual-porosity reservoir based on other prior research in Pike County, Kentucky[12]. The primary porosity is a low permeability matrix. Gas is stored in the matrix porosity. The secondary porosity system in the Berea consists of one or more sets of natural fractures. These fractures are responsible for the majority of the flow capacity, but only a very small part of the total pore volume.

The most crucial part of any history match study is the reservoir description. The description includes an assumed size and shape of the reservoir, which is used to design the simulation grid. Other data, which must be specified as input data to the simulator, are porosity and permeability of the matrix and natural fractures, number of orthogonal fracture sets, and fracture spacing. SHALEGAS allows these properties to be varied throughout the grid system.

The best history match of the injection/falloff test in the Upper Berea in the Ford Motor Company #165 well (**Fig. 12**) includes the following:

- Reservoir pressure of 190 psi
- 21 feet of net pay
- Porosity of 5.4%
- Permeability of 0.05 md
- Fracture width of 0.000765 inches during injection
- Fracture width of 0.00045 inches during the falloff
- Hydraulic fracture length of 100 feet
- Conductivity of 0.4 md-ft.

We did not use a dual porosity model because of the lack of information on the natural fracture system. A single porosity model adequately reproduces the pressure and rate history.

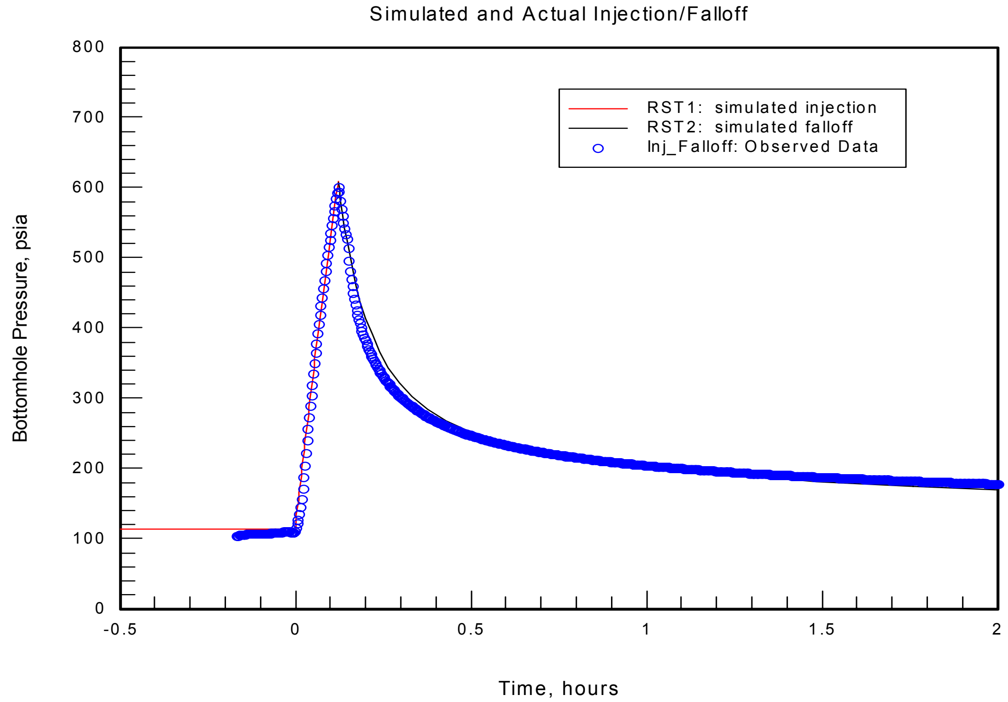

Fig. 12 – History match of injection/falloff test.

The above data from the history match of the injection/falloff test was used to history match the past production for the Upper Berea. As stated above the gas flow test of the Upper Berea after it was isolated was too small to measure. The production simulation using the history match data indicates the zone would currently be producing a rate of less than 1 Mscf/D as shown in **Fig. 13**.

EPC expected the reservoir pressure for the Upper Berea to be approximately 300 psi or the typical pressure found in wells that have also produced a few years. Since the Upper Berea was found to be nearly unproductive it could be expected to find reservoir pressure close to the original pressure of approximately 700 psi. A quick review of surrounding wells show there are three wells within 2000 feet of Ford Motor Co. #165 that each had produced more than 200,000 Mscf. It is possible that these three wells have depleted the pressure in the Upper Berea, especially in any possible existing fracture network. Since the history match of the injection/falloff test indicates a very narrow fracture, this is most likely a natural fracture and could be part of a fracture network.

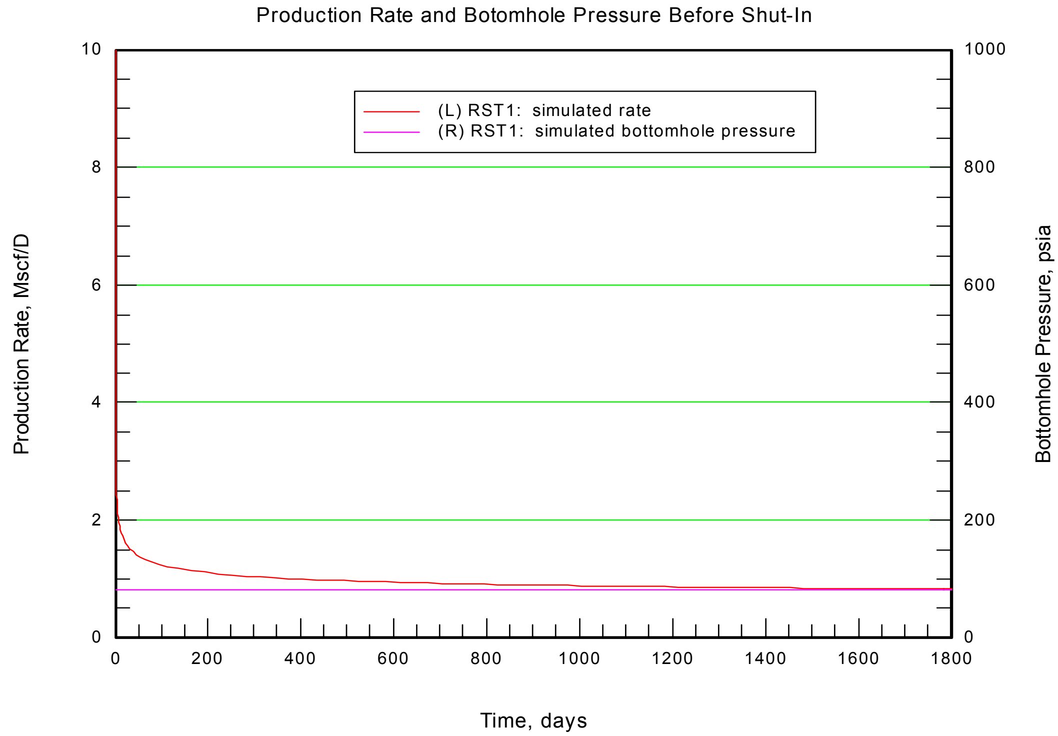

Fig.13 – History match of Upper Berea production.

5.9 Re-Stimulation of the Upper Berea

EPC decided to restimulate the Upper Berea using a nitrogen fracture stimulation. 289 Mscf of nitrogen at an approximate rate of 20,000 scf/min was used. The well was flowed back on a ¾ inch overnight. Gas test the next morning was 47 Mscf/D. The well was put back in-line. The well produced 19 Mscf the first day and 8 Mscf the second day. The well was shut in for two days and had a shut in pressure of 120 psig. The tubing and packer were pulled and the bridge plug was retrieved. The well was put back on production. The Upper Berea was estimated to be producing 6 Mscf/D after 30 days of production.

A best fit history match of the production and pressure buildup after the nitrogen restimulation was performed **Fig. 14**. The results are as follows:

- Fracture half length of 100 feet
- Fracture width of 0.00605 inches
- Fracture conductivity of 1,000 md-ft

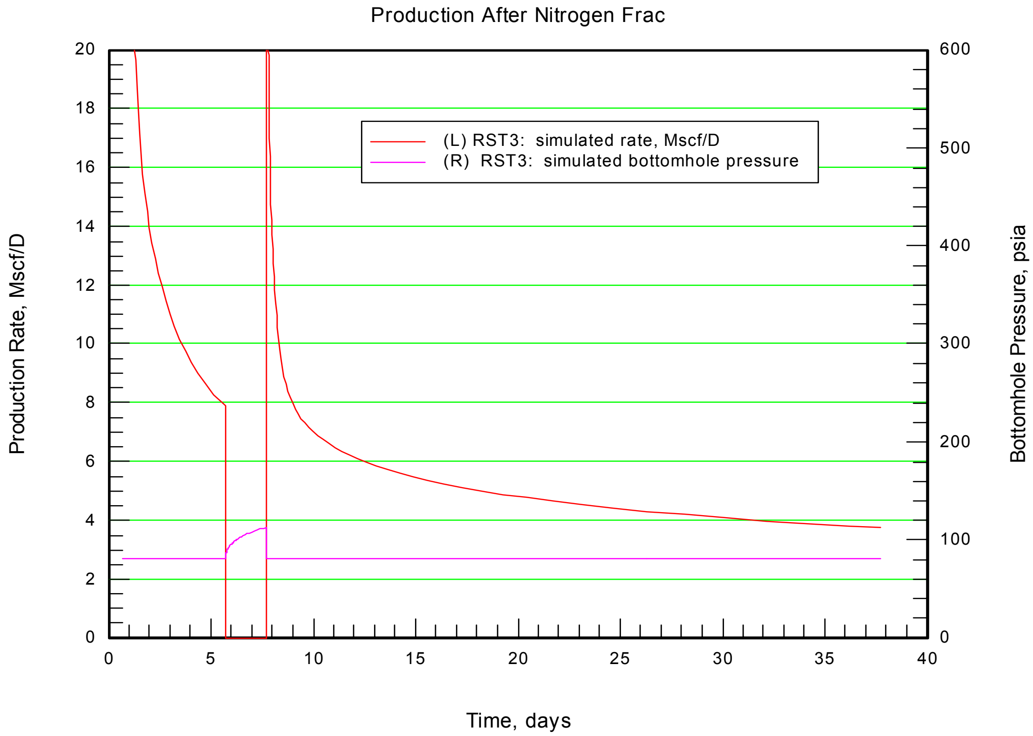

Fig. 14 – History Match of Upper Berea After Restimulation

The history match indicated that the restimulation probably created a wider fracture with the same initial length. This slightly improved performance. It is uncertain how long this fracture will remain open or what width it may retain due to the lack of proppant.

This well was a poor restimulation candidate due to the low reservoir pressure (190 psi) and the existence of a fracture (100 feet length and .00045 inches wide). The restimulation did increase the width of the fracture from 0.00045 to 0.00605 inches, but did not increase the length of the fracture. The well production improved from too small to measure to 6 Mscf/D, but the production will continue to decline and the zone has an estimated recovery of 14 MMscf. At an approximate cost of $30,000 this restimulation was uneconomic.

While the result of FMC #165 was uneconomic, this was due mainly to the low current reservoir pressure. If the reservoir had a more normal reservoir pressure of 500 psi, the well would have had production rates more than 5 times higher and an estimated recovery of 65 MMscf. The restimulation would have been easily economic. It is important that a reasonable estimate of reservoir pressure be known prior to a restimulation to determine the economics. The minimum requirement for economic recompletion would be approximately 10 Mscf/D initial production rate or a reduction of cost below $20,000.

Future research and development should attempt to find quicker and cheaper methods to determine if zones have bee stimulated effectively. This could include methods to perform very short-term pressure buildup tests which would assist in determination of current reservoir pressure.

APPENDIX A

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APPENDIX B

Production Logging candidates (4/20/01)

#	Wellname	API	Completion (-stages; / zones)	Tubing	Goal	Estimated Cost	Costs to Drilling AFE - Y/N	Activity	Fluid Level Shot (feet fluid above bottom perf	Date of Swab	Amount of fluid found above bottom perf by rig	Total Fluid Recovered (bbls water/bbls oil)	Prod. Rate before swabbing (mcfd)	WHP (psig)	Line pressure before swabbing (psig)	Prod rate after swabbing (mcfd)	Prod. Log date	Producing Rate while logging (meter - mcfd)	Production Log determined Rate (mcfd)	Production Log determined fluid level (ft)	Feet fluid over bottom perf (ft)	Rig TD/LTD (ft)	Total Cost $$ (dozer, trucking, rig, prod log)	Producing Rate 30 days after swabbing (mcfd)	Water / Oil Analysis Results (ppm Cl / deg API)	Contribution Percentage by Zone as determined by Prod. Log	Comments - drill out baffles, plugs, salt, scale, parraffin, etc.
	Eastern Gas & Fuel 168	4703905312	LDS-UDS/G/B-MW-BL-Rav	Yes	DS & shallow zonal contribution for offset completion design	$6,000	Y	POOH w/ tbg / swab	NA	2/12/2001	NA	0	32	69 csg / 54 tbg	27	238	19-Feb	135	158	4445	80	4537/4536		113		Ravencliff - 8%; Big Lime - 3%; Middle Weir - 69%; Gordon/Berea/Upper Shale - 15%; Lower Shale - 5%	Note: Header % was wrong. Leave SN depth the same.
									NA	2/12/2001	NA	0	226	45 csg	27												
2	Eastern Gas & Fuel 186	4703905323	LDS-UDS/G/B-W/BL	No	DS & shallow zonal contribution for offset completion design (all N2 completion)	$3,500	Y	swab	649	13-Feb	3100	22	74	42 csg	40	217								84		Upper Weir/Big Lime - 20%; Gordon/Berea - 15%; Upper Shale - 27%; Lower Shale - 38%	Run tbg. Set SN @ 5300'.
								swab		14-Feb	4600	36	142	48 csg	45	217											
								swab		15-Feb	4600	3.8	201	52 csg	47.5	180											
								swab		22-Feb	4100	17	147	47 csg	45	145	22-Feb	146	220	4928	481	5425/5426			110000		
3	Eastern Gas & Fuel 191	4703905330	LDS-UDS/G/B-W/BL/MAX	Yes	DS & shallow zonal contribution for offset completion design	$6,000	Y	POOH w/ tbg	NA	13-Feb	NA	0	155	142 csg / 103 tbg	65	321	19-Feb	291	330	5197	250	5540/5501		184	91689	Lower Maxton - 30%; Big Lime - 2%; Weir - 28%; Gordon/Berea - 18%; Upper Shale - 4%; Lower Shale - 18%	Leave SN depth the same.
								POOH w/ tbg/swab	NA	14-Feb	347	2.25	317	90 csg / 90 tbg	75	240											Losing fluid to perfs while swabbing.
								Swab	NA	15-Feb	NA	0.4	304	85 csg	75	149											
4	Briar Mountain 23	4703905341	LDS-UDS/G/B-UW-BL-MAX	Yes	DS & shallow zonal contribution for offset completion design (originally strap tested)	$6,000	Y	Blow down	NA	NA	NA	0	227	354 csg / 300 tbg	62.5	LOON	20-Feb	282	430	5594	638	6217/6220		256	91866	Middle Maxton - 48%; Lower Maxton - 2%; Big Lime - 10%; Upper Weir - 20%; Gordon/Berea/Upper Shale - 5%; Lower Shale - 15%	Blow down well - found pinched. On 3/17 - well flowing 256 mcfd w/ 284# whp - fluid problems.
								POOH w/ tbg/swab	NA	16-Feb	scattered	9	NA	60 csg	62.5	207											Leave SN depth the same.
5	Siler 32	4700501521	LDS-UDS-BI-BL	Yes	DS & shallow zonal contribution for offset completion design	$6,000	Y	POOH w/ tbg	NA	26-Feb														49	85000	Big Lime - 20%; Big Injun - 25%, Upper Devonian - 53%; Lower Devonian - 2%	Run single string 1 1/2. Set SN @ 3415'.
								swab		27-Feb	None	0.33	47	20 csg	17.5	50	2-Mar	58	62	4325	0	4396/4351					
								swab		28-Feb	None	0	NA	NA	NA	NA											
6	Carbon Fuel 46	4703905348	LDS-UDS-G/B-LW-UW-BL	Yes	DS & shallow zonal contribution for offset completion design	$6,000	Y	POOH w/ tbg	NA	15-Feb	NA	0	85	123 csg / 100 tbg	44	131	20-Feb	83	80	5300	460	5760/5772		67		Big Lime - 25%; Upper Weir - 15%; Lower Weir - 5%; Gordon/Berea - 25%; Upper Devonian - 25%; Lower Devonian - 5%	Note- header % was wrong.Set SN @ 4400'.
								POOH w/ tbg/swab	NA	16-Feb	NA	5	114	50 csg / 50 tbg	43	97											
7	Pocahontas 42	4701900920	LDS-UDS/B-W/SQ/BI-BL	Yes	DS & shallow zonal contribution for offset completion design	$6,000	Y	POOH w/ tbg	NA	19-Feb	NA	0	40	106 csg / 66 tbg	65	91								40	116000	Big Lime/Lower Maxton - 30%; Weir/Big Injun/Squaw - 55%; Berea/Upper Shale - 13%; Lower Shale - 2%	Recovered 2 rabbits from well on day 1.
								swab	NA	20-Feb	1980	28.8	91	77 csg	70	59											Set SN @ 4200'.
								swab	NA	21-Feb	280	2.5	66	73 csg	68	66	26-Feb	70	92	5488	492	6000/6025					
8	Jefferey Manufacturing 10	4701900897	LDS-UDS-G/B-LW/UW-BI-BL-MAX	Yes	DS & shallow zonal contribution for offset completion design	$6,000	Y	POOH w/ tbg	NA	19-Feb	NA	0	41	167 csg / tbg-shut in	58	79								43	143000	Maxton - 40%; Big Lime - 15%, Big Injun - 15%; Weir - 20%; Gordon/Berea - 5%; Upper Shale - 5%; Lower Shale - no contribution.	Well found feeding off casing.Set SN @ 3400'.
								POOH w/ tbg/swab	3650	20-Feb	2642	18.5	100	68 csg	68	85											Losing approx. 75% of swab load to perfs.
								swab	3900	21-Feb	2292	6.5	78	66 csg	65	47	22-Feb	68	118	3918	2374	6174/6100					LTD varies significantly from service rig TD because tools were left in the hole and loggers were instructed to stay off bottom.
9	Eastern Gas & Fuel 152	4703905261	L/UDS-G/B-W/BL/MAX	No	DS & shallow zonal contribution for offset completion design	$6,000	Y		NA	NA	NA	0.4	245*	36 csg	33	375								706			*Clean out sd 1514-32' - well kicked off - recover frac ball - flow to clean up.
									NA	NA	NA	0	361*	200 csg	32	425											*Abandon exercise - no swabbing done - remove from production log candidate list.
10	Wood 9	4700501712	LDS/UDS/B/BL	No	DS & shallow zonal contribution for offset completion design	$6,000	Y	swab	813	22-Feb	499	8.5	55	28 csg	20	49	2-Mar	38	62	4890	58	5000/5059		37		Big Lime - 23%; Berea - 30%; Upper Shale - 44%; Lower Shale - 3%.	Fluid recovery est. 50% oil. Did not tag TD - just cleared bottom perf.

2	Ritter 348	4710901945	G/B-BL-Rav	Yes	Zonal contribution with comparison of frac tracer survey	$6,000	N	POOH w/ tbg	NA	9-Mar	NA	0	175	73 tbg 73 csg	33	NA								215	46021		
								POOH w/ tbg swab	NA	12-Mar	0	0	194	30 csg	30	156	16-Mar	234	500	0	0	3800/3781				Ravencliff - 11%; Big Lime - 66%; Gordon/Berea - 23%	Well dry - tubing will not be run back in after logging - salvage for use elsewhere. Large discrepancy between metered flow and log determined flow.
3	Pocahontas/Carnegie 2	4705901386	LDS-UDS-BL	No	DS-Rhinestreet contirbution for offset development	$3,500	Y	swab	NA	2-Mar	1255	20	88	25 csg	7	63	8-Mar	96	92	5110	45	5159/5164		99		Big Lime - 40%; Upper Shale - 20%; Lower Shale - 40%	
								swab	NA	5-Mar	NA	0.5	99	30 csg	9	NA											
4	Pardee 93	4704501280	LDS-UDS-B/W-BL	No	DS & shallow zonal contribution for offset completion design	$3,500	Y	swab	674	1-Mar	1134	28	54	90	32	NA	7-Mar	380	380	5904	787	6757/6748		94		Big Lime - 12%; Berea/Weir - 73%; Upper Shale - 10%; Lower Shale - 5% or less.	Well was shut in prior to production logging due to curtailment with CNG; well was vented for 1 hr to bring flowing pressure down to line pressure - may have brought fluid in during blow down.
								swab	NA	2-Mar	0	0	110	89	38	89											Prod. Rate after swabbing after 1 hr - still increasing.
5	Hinchman B-2	4704501330	LDS-B/G-W/BL-MAX	Yes	DS & shallow zonal contribution for offset completion design	$6,000	Y	swab	NA	5-Mar	1886	1.5	74	NA	15	NA	13-Mar	115	120	4911	430	5350/5425		105	66892	Middle Maxton - 20%; Weir/Big Lime - 35%; Gordon/Berea - 35%; Lower Shale - 10%	
								swab	NA	6-Mar	1341	17.5	82	43 csg	17	NA											
								swab	NA	7-Mar	NA	5	84	NA	15	NA											
6	Elk Creek 36	4705901308	LDS-UDS-B-BL	No	DS-siltstone & shallow zonal contribution for offset completion design	$3,500	Y	KO Frac Plug & baffle	0	2-Mar	NA	0	96	95	95	NA	8-Mar	103	157	4928	512	5490/5408		121		Big Lime - 35%; Berea - 35%; Upper Shale - 20%; Lower Shale - 10%	Discrepency between service rig TD & loggers TD (82'). KO'd frac plug, baffle and cleaned out to 5490'.
								KO baffle & sd pmp	NA	3-Mar	NA	0	96	95	95	NA											
								Sd pmp & swab	NA	4-Mar	NA	16	93	95	95	NA											

7	Elk Creek 42	4704501367	LDS-UDS-B-BL	No	DS-siltstone & shallow zonal contribution for offset completion design	$3,500	Y	swab	511	5-Mar	2685	12	103	NA	24	NA	13-Mar	176	203	5478	407	5904/5736		158		Big Lime - 20%; Berea - 23%; Upper Shale - 37%; Lower Shale 20%	TD reached with PL tool was significantly shallower (268') than rig TD.
								swab		6-Mar	NA	12	144	50 csg	20	NA											
8	Ritter 235	4710901078	RAV-G-DS (can't find file)	Yes	DS-zonal contribution for offset completion design	$9,000	Y	POOH w/ dual strings	NA	13-Mar	NA	0	11 deep 86 shallow	44 deep 40 shallow	40	NA	20-Mar	72	85	5872	270	6195/6159			73860	Ravencliff - 80%; Lower Maxton - 0%; Gordon - 10%; Upper Shale - 0%; Lower Shale - 10%	Sand pumped 10' of fillup out of well 6185-6195'.
								POOH w/ dual strings / swab	NA	14-Mar	0	0	121 total	NA	50	NA											
9	Island Creek 'D' 86	4704501274	DS-BL	No	DS-Rhinestreet & shallow zonal contribution for offset completion design	$3,500	Y	swab	82	26-Feb	623	10.3	284	80 csg	72.5	301								261			
								swab		27-Feb	NA	5	301	80 csg	72.5	NA	5-Mar	283	275	284	23	4414/4413				Weir/Big Lime - 85%; Upper Shale/Gordon/Berea - 12%; Lower Shale - 3%	
10	Island Creek 'D' 29	4704501156	LH-G-B	Yes	DS & shallow zonal contribution for offset completion design	$9,000	Y	POOH w/ tbg	NA	27-Feb	NA	0	35	33	12	84.5	7-Mar	NA	155	4464	34	4527/4519		110	75680	Big Lime - 60%; Berea/Upper Shale - 10%; Lower Shale - 20%; Rhinestreet - 10%	Rerun single string of tubing; set SN @ 4400' - Rhinestreet is contributing 10% of flow.
								POOH w/ tbg/swab	NA	28-Feb	498	12	NA	NA	NA	NA											Need additional Well Info from D&C personnel.
								swab	NA	1-Mar	NA	0	NA	NA	14	NA											
11	Cole & Crane B26	4704501285	DS-B-BL	No	DS & shallow zonal contribution for offset completion design	$3,500	Y	POOH w/ tbg	317	26-Feb	NA	0	NA	NA	NA	NA	5-Mar	48	66	4520	194	4750/4718		55		Big Lime - 20%; Berea/Sunbury Sh - 30%; Upper Shale - 47%; Lower Shale - 3%	
								swab		27-Feb	824	18	35	33 csg	12	NA											
								swab		28-Feb	0	0	84	NA	17	NA											
12	Thacker A-7	4705901273	DS-BL(can't find file)	No	DS-Rhinestreet & shallow zonal contribution for offset completion design	$3,500	Y	swab	821	8-Mar	610	9	36	NA	5	72	15-Mar	75	80	5021	89	5120/5117		61		Big Lime - 20%; Weir/Berea - 0%; Upper Shale - 70%; Lower Shale - 10%	
								swab	NA	9-Mar	0	0	75	NA	5	91											
13	David Francis Trust 4*	4705901316	LDS-UDS-B	No	DS comparison - Rhinestreet	$3,500	Y	swab	205	12-Mar	NA	6	NA	70	70	NA	16-Mar	74	80	4264	30	4339/4330		69	44475	Big Lime - 40%; Upper Shale - 52%; Lower Shale - 8%	Found meter reading with a negative differential - contact Kinzer for repair. Follow-up with Kinzer for adjustments.
								swab		13-Mar	0	0	81	70	61	NA											
14	David Francis Trust 5*	4705901317	DS-B-BL	No	DS comparison - Rhinestreet	$3,500	Y	swab	227	10-Mar	727	12	72	70	70	85	15-Mar	75	68	4076	51	4156/4151		71	55395	Big Lime - 20%; Berea - 20%; Lower Shale - 60%	
15	Pardee Land 89	4700501612	BL/BE/DS/RH	Yes	Test area for new 2001 drilling (Rhinestreet contribution) - well makes 2 BW/mo	$6,000																					
16	Southern Land 32	4700501683	MX/BL/WE/BE/DS	Yes	BI/WE/BE - N2 gas fraced - 1 stage BI/WE/BE; also CO2 fraced SH; 1 BW/mo	$6,000																					
17	A.H. Cole B-16	4704501173	BL/BE/DS	Yes	Rhinestreet Contribution - Dual 1.9" strings of tubing	$9,000																					
18	Pocahontas/Carnegie #1	4705901384	BL/BE/GD/DS/RH	No	Rhinestreet Contribution	$4,000																					
19	Isand Creek D55	4705901169	BL/BE/GD/DS/RH	Yes	Rhinestreet Contribution - Dual 1.9" strings of tubing	$9,000																					
20	Isand Creek D23	4705901149	BL/BE/GD/DS/RH	Yes	Rhinestreet Contribution - Dual 1.9" strings of tubing	$9,000																					
								swab	NA	12-Mar	0	0	79	75	73	NA											
1	VP-4018		LDS-UDS-WE-BL	Yes	Evaluate zonal contribution - especially Weir for use on future wells.	$6,000	Y	POOH w/ tbg / swab	NA	14-Mar	592	6					19-Mar	61	65	3868	122	dd/4067		95		Big Lime - 20%; Weir - 10%; Cleveland Shale - 50%; Lower Huron - 20%	
2	VP-4023		LDS-UDS-WE-BL	Yes	Evaluate zonal contribution - especially Weir for use on future wells.	$6,000	Y										19-Mar	110	114	3428	216	dd/3720		93		Big Lime - 78%; Weir - 5%; Cleveland Shale - 14%; Lower Huron - 3%	
1	EPC (Anthony Frashure TR) 2 KF4128		Coffe-US-LS (2 stage)	No	Coffee Shale was completed - evaluate for contribution.	$3,500	Y	Swab	NA	4/3/2001	-1'	1 wtr	132	47	47	NA	4/6/2001	192	70	3145	-4'	3193 / 3208			32385	Berea/Upper Shale 55%, Lower Shale 45%	
2	KF1611		US-LS (2 stage)	No	Underperforming well - eval for zonal contribution. Identify problem zones.	$3,500	N	Swab	NA	3/29/2001	-5'	.3 wtr	16	45	45	NA	4/3/2001	16	27	3484	46'	3558 / 3553			72420	Berea/Upper Shale 50%, Lower Shale 50%	
3	KL4390		BL-US-LS (3 stage)	No	Underperforming well - eval for zonal contribution. Identify problem zones. BL thief zone? Info important for offset development - BL or no BL?	$3,500	Y	Swab	NA	3/29/2001	531'	10 wtr / 15 oil	4	7	7	NA	3/30/2001	27	38	1880	351'	2293 / 2292			34.1	Big Lime 10%, Berea/Upper Shale 10%, Lower Shale 80%	
4	6644 DD		US-LS (3 stage)	No	Eval zonal contribution for future wells.	$3,500	Y	Swab	NA	3/29/2001	480'	.2 oil	19	30	30	NA	4/4/2001	19	23	2616	-1'	2650 / 2654			25	Berea/Upper Shale 10%, Lower Shale 90%	
5	Rouge Steel 2	1619586628	Be-US-LS	No	6 offsets planned in 2001 - zonal contribution definition	$3,500	Y	Swab	324' 12/5/00	3/28/2001	432'	4.8 wtr	118	36	36	NA	4/2/2001	68	89	5392	840	4288 / 4252			32988	Berea/Upper Shale 60%, Lower Shale 40%	
6	Ford Motor Co. 1-094	1619590712	BL-Clev-LowHur	No	2 offsets planned in 2001 - zonal contribution definition	$3,500	Y	Swab	NA	3/27/2001	526'	14.3 oil	156	42	42	NA	3/30/2001	184	190	4320	704'	5133 / 5118			35.8	Big Lime 10%, Berea/Upper Shale 80%, Lower Shale 10%	May need tbg.
7	Smith-Carrs Fork Unit #2-1	1611989884	BL-Clev-LowHur	No	4 offsets planned in 2001 - zonal contribution definition	$3,500	Y	Swab	NA	4/2/2001		3.25 wtr / 3.25 oil	37	45	45	NA	4/9/2001	67	82	3345	313'	3665 / 3678			58,574	Big Lime10%, Upper Shale/Berea 70%, Lower Shale 20%	

8	Hatcher 4-105	1607191663	BL-Clev-LowHur	Yes	3 offsets planned in 2001 - zonal contribution definition	$6,000	Y	MIRU	NA	3/14/2001			48.3	25	25	NA	3/22/2001	55	57	3292	39	3450 / 3446	6393	62	40	Big Lime 0%, Upper Shale/Berea 50%, Lower Shale 50%	Tbg re-ran w/ SN at original depth.
								TOOH w/tbg; swb		3/15/2001	125'	.6 oil															
9	Hatcher 4-060	1619590909	Bl/We-Clev-LowHur	No	1 offset planned in 2001 - zonal contribution definition	$3,500	Y	Swb	NA	3/21/2001	600'	1.1 wtr / 9.6 oil	16	30	30	NA	3/26/2001	15	15	2704	490	3210 / 3209			35.5	Big Lime/Borden 30%, Berea/Upper Shale 65%, Lower Shale 5%	May need tbg.
10	Republic Steel 2-108	1619591756	Mx-BL-Clev-LowHur	No	4 offsets planned in 2001 - zonal contribution definition	$3,500	Y	Drl FP	NA	3/12/2001			98.2	45	45	NA	3/22/2001	132	---	---	---	4150 / 4148	6244	119	53455	Due to large volume of fluid in hole, an accurate interpretation cannot be made. Substantial flow exists from MX & U DS 3300-3320'	Found dump valve stuck open prior to logging- loaded w/ gas cut fluid.
								Drl FP		3/13/2001																	
								Swb		3/14/2001	2323'	32.1 wtr															Run tbg w/ SN @ 4020' - under original AFE.
11	Colony Coal & Coke 2-101R	1619590679	BL-Clev-LowHur	No	5 offsets planned in 2001 - zonal contribution definition	$3,500	Y	Swb	NA	3/22/2001	150'	5.3 wtr	86	77	77	NA	3/27/2001	114	130	5051	91	5189 / 5178			74551	Big Lime 10%, Berea/Upper Shale 50%, Lower Shale 40%	
12	EPC (Hall, WD) KF 4427	1611991010	We-Clev-LowHur	No	No offsets planned in 2001 - zonal contribution definition	$3,500	N	Swab	NA	3/30/2001	104'	4.2	46	40	40	NA	4/4/2001	79	108	2843	169	3068 / 3084			58226	Borden/Weir 15%, Berea/Upper Shale 77%, Lower Shale 8%	
13	Chesapeake Min. 2-051	1619591303	BL-Clev-LowHur	No	2 offsets planned in 2001 - zonal contribution definition	$3,500	Y	Swb	NA	3/21/2001	250'	9.5 wtr	76	41	41	NA	3/27/2001	70	100	4253	239	4489 / 4537			86991	Big Lime 0%, Berea/Upper Shale 70%, Lower Shale 30%	
14	Emperor Coal 1-285	1619590986	BL-Clev-LowHur	No	2 offsets planned in 2001 - zonal contribution definition	$3,500	Y	Swab	70' 2-21-01	3/28/2001	70'	1.8 wtr	57	38	38	NA	4/2/2001	57	72	4400	70	4546 / 4529			50359	Big Lime 55%, Berea/Upper Shale 25%, Lower Shale 20%	
15	Ford Motor Co. A-165	1619588353	Be-Clev-LowHur	No	4 offsets planned in 2001 - zonal contribution definition	$3,500	Y	Swab	NA	3/28/2001	fl @ 4050'	6 wtr	39	40	40	NA	4/2/2001	39	40	4222	143	4398 / 4386			58658	Berea/Upper Shale 80%, Lower Shale 20%	
16	KF 4300 JJ Kendrick	1619591330	We-Clev-LowHur	No	No offsets planned in 2001 - zonal contribution definition	$3,500	N	Swab	NA	4/3/2001	546'	10 oil	61	50	50	NA	4/6/2001	127	62	4245	67	4189 / 4216			50312	Weir 15%, Berea/Upper Shale 45%, Lower Shale 40%	
17	Solvay-Coleman 2-018	1619591342	Mx-BL-Clev-LowHur	Yes	No offsets planned in 2001 - zonal contribution definition	$6,000	N	TOOH w/tbg	NA	3/20/2001			129.3	37	37	NA	3/30/2001	168	220	3530	589	4125 / 4130	9093		68179	Maxton 25%, Big Lime 10%, Berea/Upper Shale 42%, Lower Shale 23%	Re-ran tbg w/ SN at original depth.
								TOOH w/tbg; swb		3/21/2001	219'	4.8 wtr															
18	Chesapeake Mineral B-39	1619582986	US-LS	Yes	6 offsets planned in 2001 - zonal contribution definition	$6,000	Y	TOOH w/tbg	NA	3/16/2001			SS 17.5 DS 33.4	28	28	NA	3/26/2001	41	25	4114	129	4249 / 4318	7568		40.4	Interpretation is very difficult due to low volume & fluid falling on spinner.	Re-run single string of 2 3/8" tbg w/ SN @ 4150'. AFE approved.
								TOOH w/tbg		3/19/2001																	
								Swb		3/20/2001	125'	2.4 wtr / 2.4 oil															
19	Republic Steel Corp. 79	1619579791	US-LS	No	5 offsets planned in 2001 - zonal contribution definition	$3,500	Y	Swb	NA	3/22/2001	150'	2.4 wtr	14	35	35	NA	4/3/2001	22	38	4222	44	4289 / 4280			74204	Berea/Upper Shale 60%, Lower Shale 40%	
20	EPC (John Godsey #1) KF 918	1619390840	Clev-LowHur	No	2 offsets planned in 2001 - zonal contribution definition	$3,500	Y	Swab	NA	4/3/2001	315'	3.5 wtr	105	70	70	NA	4/5/2001	76	77	3680	135	3799 / 3817			53514	Berea/Upper Shale 100%, Lower Shale 0%	
21	Gibson E. 2 KL 1446	1611990836	BL-Clev-LowHur	No	3 offsets planned in 2001 - zonal contribution definition	$3,500	Y	Swab	NA	4/2/2001	148'	3 oil	60	20	20	NA	4/5/2001	64	71	2454	44	2518 / 2525			47002	Berea/Upper Shale 30%, Lower Shale 50%	3 perfs covered w/debris.
22	KF 4448 (Harve Johnson)	1607191151	BL-Clev-LowHur	No	3 offsets planned in 2001 - zonal contribution definition	$3,500	Y	Swab	NA	4/3/2001	474'	10 oil	39	45	45	NA	4/6/2001	65	68	3655	219	3903 / 3905			54791	Big Lime 18%, Berea/Upper Shale 58%, Lower Shale 24%	May need tbg.
23	KF 1604 (W.D. Hall)	1611991031		No	0 offsets planned in 2001 - zonal contribution definition	$3,500	N	Swab	NA	3/30/2001	323'	16 wtr	33	73	73	NA	4/4/2001	38	50	2924	299	3248 / 3256			36.5	Weir 15%, Berea/Upper Shale 75%, Lower Shale 10%	
					TOTAL COST ESTIMATE OF PRODUCTION LOGGING PROGRAM:	**$258,500**																					

Environmental and Regulatory Issues Relating to the Utilization of Produced Water from Oil and Gas Operations

Final Report for the Environmental and Regulatory Issues Relating to the Utilization of Recycled Produced Water from Oil and Gas Operations:
1: A Study of Existing Policies of State and Federal Agencies
2: Development of an Approved Program for Re-Use of Water Objectives of Project during the Period 05/15/2001 to 09/30/2002

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Final Report

Date: January 7, 2003

Project Title: Environmental and Regulatory issues Relating to the Utilization of Produced Water from Oil and Gas Operations

Environmental and Regulatory Issues Relating to the Utilization of Recycled Produced Water from Oil and Gas Operations:

1: A Study of Existing Policies of State and Federal Agencies
2: Development of an Approved Program for Re-Use of Water Objectives of Project

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Final Report

Environmental and Regulatory issues Relating to the Utilization of Produced Water from Oil and Gas Operations

Management Abstract

Management and disposal of produced water is one of the most challenging problems associated with the oil and gas industry. Very large volumes of produced water, or brine, are produced along with the oil and gas resources. The current management methods available, such as reinjection of the produced water, are costly to the industry and the environment. The management of produced and injected water is a major emphasis in the industry today. There are various water issues in the industry as well, such as treatment of wastewater, its effects on the environment, and a growing concern for the availability of water in arid lands.

The project is a study of the existing policies of two oil and gas producing regions. We have been working with federal and state agencies to develop guidelines for companies to follow for making this new source of fresh water available for productive use. We have met with appropriate agencies as new rules and regulations are considered and work with those seeking to remove some of the roadblocks to the re-use of treated produced water.

The following is a report of the research completed for this project. The report includes a discussion of results, accomplishments, and conclusions that have been reached concerning the environmental and regulatory issues relating to the utilization of produced water from oil and gas operations. We have also produced a roadmap of the steps needed to get this technology accepted by the public and the regulatory community.

Our first work was directed toward identifying the agencies and regulatory practices that are encountered when developing a produced water reuse program. The Texas A&M Produced Water Treatment Project has been used as an example of the type of project that operators would plan. The A&M program utilizes fresh water resources obtained from produced water treatment to restore native rangelands.

In 2002, we have focused on the specific steps a company would take in developing a project. This step includes a description of our group’s work in creating a project in West Texas. We have developed a preliminary set of guidelines that companies can use as a roadmap to integrate a fresh water resource recovery program into their own produced water management program.

Finally we have developed a reference contact list. Agencies we have contacted were collected in a database for members of the SWC. The database contains contact information on state and national officials, water treatment companies, and individuals involved with these types of programs nation-wide. With our work specific to Texas, we have been coordinating with the Texas Railroad Commission, the regulatory authority for our state. The final portion of the project involves the establishment of information on the Texas A&M GPRI web site describing the water project (http://www.gpri.org).

Final Report

Environmental and Regulatory issues Relating to the Utilization of Produced Water from Oil and Gas Operations

I. Introduction

Impending Environmental Problems Facing the Oil & Gas Industry

A water crisis is looming in many parts of the United States. Areas in the American West and Southwest are especially critical, with many areas currently coping with a series of droughts that have significantly altered land-use behavior and impacting both urban and rural communities. Throughout these regions, water quantity and quality issues increasingly are being recognized by state policy makers, local elected officials, and the citizenry at large. In Texas, data available from the Cooperative Extension (TCE) show the pervasiveness of these concerns in the state (TCE 1999). In 1999, TCE, in a major planning effort, gathered information from over 10,000 Texas residents on critical issues confronting their communities. Those issues associated with water quantity and quality ranked among the top five priorities in 184 of the state's 254 counties (TCE 1999). It is apparent that solutions to the pressing water quantity and quality issues in Texas and other states will require innovative approaches and technologies.

A photograph of the O. C. Fisher reservoir near San Angelo Texas shows the effect of the extended drought on the city's water supply. Until summer rains in 2002 came, the reservoir was at less than 15% capacity.

Another serious water related problem faces the oil and gas producers in many of the same areas of the country. Oil and gas production is a major industry in many of the drought affected areas. A major problem for these companies revolves around the production and disposal of large quantities of water, mostly brine. Public records obtained from the Railroad Commission of Texas reveal that every day more than 400 million gallons of water are produced from oil and gas wells in the Permian Basin region of West Texas. For every barrel of oil that is produced in the region, 300 gallons of water are produced. Oil and gas companies only use about one percent of this produced water; the remaining 99% is typically disposed of through re-injection.

In Wyoming, the production of natural gas from coal beds on state and federal land is an extremely contentious issue because of the co-production of water[1]. According to the Bureau of Land Management, the average production of a coal bed methane (CBM) well is 125,000 cfd of gas and 12 gpm of water (Powder River Basin Resource Council 2002).

Water produced from a CBM well is shown overflowing a holding tank on a ranch in Wyoming (photo courtesy of New York Times[1]).

In other words, gas producing companies must manage more than 17,280 gallons of produced water per well every day. The petroleum industry and the regulatory agencies have managed this produced water as if it were a pollutant to be disposed of according to standard disposal practices. The public sees this disposal as a waste of water resources. The result? The EPA has just denied permits to the development of the natural gas resources.

In Appalachia, while not as critical, produced water management is still a significant expense of operators and while the issues facing eastern operators may be different, resolution of the problems are similar.

Beginning to Address the Problems

Controversy will continue to exist wherever CBM production is planned or where produced water from conventional oil and gas production becomes more and more difficult to manage. Recognizing that an equitable solution is urgently needed, the oil and gas sector, lawmakers and regulatory agencies are studying ways to resolve the conflicting interests of the stakeholders in the drama. In 2002, there were numerous meetings to bring together those who could effect changes in the industry.

Most industry groups recognize that technology exists to remove contaminants from produced water and to create a resource that could be used to supplement current water supplies in water-short regions. New Mexico groups are leading the way in legislative action. Texas A&M's Texas Water Resources Institute (TWRI) is in the forefront of technology development with two field demonstration projects in Texas to utilize fresh water recovered from oil field brine to rehabilitate rangelands and wildlife habitats.

The solution to the problem is for all groups to realize that produced water is a resource not a pollutant and that wise management of the resource will bring about increased revenue to operating companies, more fresh water resources for the public sector and less burden on the regulatory agencies who are responsible for oversight of oil and gas and the environment.

A Role for the Stripper Well Consortium

Regulations[2-5] governing the disposal of produced water have become more stringent over the years. Discharge of produced water is not allowed on land and in streams and rivers where the produced water can come in contact with the surface water. At the present there are no clear-cut laws and regulations in the United States dealing with the beneficial use of produced water. The SWC can become one of the advocates of change as these agencies react to new technology and new environmental imperatives.

The SWC represents a voice of the independent producer. Being technology oriented, the SWC can serve as a champion of new practices and processes that benefit the independent. This study by Texas A&M, funded by the SWC is the first step on the way to gaining acceptance of the concept of value placed upon produced water. The following report will review technology to recover fresh water from produced brine and show the potential benefits that could be derived from the development of this resource. The study will describe our efforts to identify ways to get projects to the field. We will show how (and why) local, state and federal agencies regulate this activity and will present suggestions for ways that members of the SWC can influence changes in these agency's actions to make beneficial use of produced water easier to achieve.

II. Fresh Water Resources from Oil Field Waste

Types of Beneficial Uses: Environmental Impacts

This report discusses water management options specific to independent operators. There are many opportunities for using produced water. However, the ability to identify an alternative as being feasible will likely be dependent upon very site-specific and situation-specific criteria. Fresh water resource recovery from produced water is the example cited in our work, but many other options are available. Options such as produced water impoundment and release, re-injection into fresh water aquifers, and resource recovery all being considered by our industry and field demonstrations are being planned by a number of groups..

Several impediments to the widespread adoption and diffusion of water treatment technology such as the TWRI program must still be addressed. . Discharge of produced water to the surface waters and seawaters is prohibited under the Clean Air and Water Act until certain criteria are met.[4,5] There are no market mechanisms and incentives currently in place for the oil and gas operators to treat water and make it available as a commodity. Oil and gas companies produce petroleum, not fresh water. They see the water produced with petroleum as a waste, not a byproduct to be re-used. It will be necessary to work with industry associations and governing bodies to identify ways to solve the problem.

However, even if oil and gas companies began producing treated water, we do not know the extent to which individuals would be willing to accept its use.

Field operations are the best way to measure the performance of the GPRI units. A number of sites are to be established in different locations so as to evaluate performance over a range of conditions including types of produced water, types of terrain and types of volumes.

The program involves environmental monitoring of test plots where natural rainfall is augmented though the use of fresh water produced by portable water treatment modules. The field project is expected to show that native grasses can be re-established in degraded areas safely at a rate more than 8 times faster than comparable methods of rangeland restoration.

Ultimately the success of brine treatment will depend upon the cost of the treatment process and whether it is comparable to the cost of brine disposal and to the cost of fresh water from other sources. Tests on components of the filtration modules have shown that brines with TDS less than 10,000 ppm can be treated and converted to fresh water of 500 ppm or less for a cost of approximately $01.0 per gallon[6]. Our goal is to reduce this cost by at least 50%. We also expect to extend the capability of the units to be able to treat brines of up to 50,000 TDS as the program proceeds.

While treatment of produced water is not new, there have been few projects where the use of the re-used water has been carefully monitored. For this project, the Texas Water Research Institute has established a task force of scientists from the Rangeland and Ecology Management Department to design, implement, and monitor discharge from the GPRI water treatment modules.

The plan is to augment the natural rainfall at a field site in a systematic manner established by hydrologists, soil scientists and rangeland rehabilitation specialists. Control sites near the treatment site will be used as baseline comparisons. One site will be monitored but otherwise no intervention is planned. The second site will augment natural rainfall with added water from a fresh water source.

The third test site will be using the same amount of added water obtained from the GPRI modules. A monitoring program is to be established by Dr. John Bickham of the Department of Wildlife and Fisheries, a noted authority on environmental toxicology.

It is important to note that the rules and regulations relating to impoundments and the CBM industry in the West are currently being modified or developed for several states. Reviewers who can provide regulatory clarification or updates to the regulatory section of this document would be appreciated.

Regulatory agencies are accustomed to handling "impoundment" projects. Impoundments represent a single management option or a combination of management options including: livestock and wildlife watering from wetlands, fisheries and recreational ponds, recharge and evaporation ponds or other combinations. Specific applications, regulations, and limitations are associated with each impoundment type. Regional limitations derived naturally from insufficient water quality, climate, or methane production prevent anyone from establishing any "universal" guidelines.

The impoundment of produced water from CBM production, for instance, can be an option utilized by operators as part of their water management practice. In some producing basins, such as the Powder River Basin, impoundments play a large role in water management practices, while in other basins impoundments may only be used during drilling operations. The impoundment of CBM water is the placement of water produced during operations at the surface in a pit or pond. There are a variety of ways in which operators can impound produced water at the surface. Impoundments can be constructed on or off channel and the regulatory authority in some states varies based on whether the impoundments are off or on channel.

Impoundments can be used for a variety of water management options including, disposal by evaporation and/or infiltration, storage prior to another water management option including injection or irrigation, or for beneficial use such as a fishpond, livestock and wildlife watering ponds or a recreational pond. The impoundment of water can be performed in any area where there is sufficient construction space. In areas with limited rainfall or drought conditions, impoundments could be used to recharge groundwater in shallow alluvial and coal seam aquifers, to provide livestock and wildlife water or for the storage of water prior to irrigation.

As stated, economics of produced water treatment depends on many factors. These factors include the amount of suspended and dissolved hydrocarbons present in the produced water, amount of suspended and dissolved solids (salts) present in the produced water[7]. Cost of treating the produced water also depends on the final quality of the permeate (treated water) that is required by treating the produced water (final TDS in the produced water).

One of the most important factors affecting the cost of treating the produced water is the amount of total recovery from produced water that is required. As the amount of recovery is increased, the operating and the capital costs increase because of the higher pressure required for higher recoveries (equipment becomes more expensive). At the same time the operating and capital cost per gallon of water treated/recovered and may go down. There is a fine balance involved in deciding the amount of water to be recovered and the minimum treated water price. This involves an optimization process with actual field testing of the water treatment module to determine the actual operating conditions for most economical treatment price for produced water treatment.

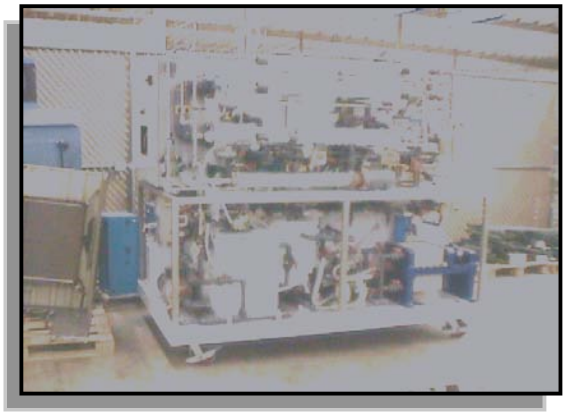
A&M Fresh Water Resources Development Program

At Texas A&M a number of scientists and engineers are working on creating new fresh water resources from oil field waste brines. These tasks are coordinated by TWRI and the Department of Petroleum Engineering [8,9].

Funding from the GPRI project will be used to design and construct field filtration modules. The GPRI modules will utilize a two-step pre-filtration step followed by two membrane filtration steps, the last being a reverse osmosis (RO) unit to remove the dissolved salts from the brine stream.

Each module is designed to treat a portion of the produced water stream for a specific field site with the reject from the RO unit being added back to the remaining produced water disposal system. Depending on the efficiency of the filtration modules, the units will be able to deliver up to 2,000 gallons per day of fresh water having less than 500 ppm total dissolved solids (TDS). The units will be placed near oil field production batteries to treat water on site to use nearby in rangeland reclamation.

Testing to select the types of pre-filtration and the type of filters best suited for treating the brine are being performed using produced brine collected from a Grimes County oil field disposal facility. Input waste streams had approximately 200 ppm crude oil in a 15,000 TDS brine. Pre-filtration reduced the brine to less than 20 ppm. Filtration and RO treatments with different types of filters results in separation efficiency of from 75% to 95% (one-pass). Optimization tests are underway to find a filter media that will maximize flux and filtration efficiency for any given oil field brine type saline system.



This picture shows a modular wastewater filtration unit that would be modified to place at a production battery. . Portable RO membrane filtration units have the capacity to recover from 1,000 to 5,000 gallons a day from oil field brine.

Plans are being made to employ the GPRI units in a number of field sites to test their efficiency and to evaluate the best combinations of pre-treatment and filter types to use for a particular type of produced brine. Presently we expect to have field sites in Texas, New Mexico, and Wyoming at GPRI sponsor's fields.

The unit's performance will be measured by their filtration efficiency, the amount and quality of the fresh water produced, and the operating costs of the units. Units will be operated over extended time periods. By monitoring the performance of the units over a range of operating conditions, and optimizing pre-filtration and filtration techniques, we expect to be able to reduce operating costs and increase filtration efficiency substantially during field operations. Water treatment with the GPRI units will be carefully monitored to measure the efficiency of the removal of hazardous material and deleterious salts.

III. Regulations on Use of Produced Water

Produced water is saltwater or brine that is produced along with hydrocarbons during the exploration and production processes of the petroleum industry. In some cases, the volume of water produced may exceed the volume of hydrocarbon production. The disposal of this water becomes costly to the industry. Discharge of produced water to the surface waters and seawaters is prohibited under the Clean Air and Water Act until certain criteria are met. The maximum allowable amount of petroleum hydrocarbons in produced water that can be discharged is 29 ppm. Discharge of produced water is not allowed on land and in streams and rivers where the produced water may come in contact with surface water.

Classification of Discharged Brine

The disposal of produced water is regulated by the U. S. Environmental Protection Agency (EPA), **http://www.epa.gov.** In many states the responsibility for monitoring and enforcing EPA regulations is suborned to state oil and gas regulatory agencies. Recognizing that the potential impact of produced water disposal varies, the EPA recognizes several sub categories of disposal options. One of these is the “beneficial use” category. These regulations are based on available technology and as technology changes, the regulations may vary.

The most influential regulation affecting a new beneficial use program for oil field produced water is the 1972 Federal Water Pollution Control Act. Together with a corresponding regulation known as the National Pollution Discharge Elimination System (NPDES), these programs control what quality water be released into the environment. As technology developments open the door to new waste water treatment, these basic regulations will be modified, but only after testing and demonstration of the beneficial effects to the community and the environment.

EPA Regulations

40 CFR 435, the Oil and Gas Extraction Point Source Category, Subpart C Onshore Subcategory, establishes there shall be no effluent discharge of produced waters. However, Subpart E-Agricultural and Wildlife Water Use, allows the discharge of produced water for agricultural or wildlife watering use if the facility is located west of 98’ meridian. Under this subpart, the water must be of good enough quality to be used for wildlife, livestock, or agricultural use and that the water be put to such use during periods of discharge.

40 CFR 435 is only applicable when State authorities deem CBM produced water as an oil and gas produced water. The State of Alabama, for example, does doe consider CBM produced water as an oil and gas extracted water and thus, is not regulated by this standard. Currently the EPA does not have CBM specific produced water effluent limitations since 40 CFR 435 was promulgated prior to initiation of current CBM operations. Section 307 (a)(1) of the Federal Water Pollution Control Act, as amended, however, does require a list of toxic pollutants and effluent standards for cyanide, cadmium, and mercury when applicable. Produced water from the Oil and Gas industry is exempt from EPA RCRA rules and standards and is therefore, not subject to 40 CFR, Part 264, which establishes performance standards for hazardous waste landfills, surface impoundments, land treatment units, and waste piles. If State authorities due or were to classify produced water as a hazardous waste *and* also deem the water as a non bi-product produced by the oil and gas industry, the above mentioned standard would apply..

As authorized by the Clean Water Act, the National Pollutant Discharge Elimination System (NPDES) permit program controls water pollution by regulating point sources that discharge pollutants into waters of the United States. The Water Permits Division (WPD) within the U.S. Environmental Protection Agency's Office of Wastewater Management manages the NPDES permit program in partnership with EPA Regional Offices, states, and tribes. NPDES permitting requirements for produced water will vary from state to state, but in general would largely depend on the quality of water and eventual use of the water. Appropriate state water quality authorities would need to be contacted to ascertain their permitting requirements.

Water Problems Caused in Part by Conflicting Regulations

Management and disposal of produced water is one of the most significant problems associated with the oil and gas industry. In Texas, more than 150,000,000 gallons of water are produced in the industry each day. The management and disposal of this water becomes very costly to the industry, as well as becoming a possible reservoir and environmental hazard. The current method commonly used throughout the petroleum industry today is reinjection of the water produced during exploration and production. This costs up to $1.30 per barrel of produced water. The preferred method for the disposal of produced water is one that adequately protects the environment and is of the lowest cost to the operator. Regulatory and monetary constraints often limit the options available, however.

The Texas Natural Resource Conservation Commission (TNRCC) estimates that by the year 2020, fresh water needs in the state of Texas will increase by more than twenty times. There are many arid regions, such as West Texas, with little fresh water resources, but with large amounts of oil, gas, and brine production. According to the Texas Railroad Commission, an excess of 400 million gallons of water are produced from oil and gas wells in the Permian Basin of West Texas with only one percent of the produced water being used at the well locations. The remaining 99% is disposed of by reinjection. The oil and gas industry is now looking into ways of using the vast amounts of produced water to benefit these areas in which a scarcity of water exists. With new technologies in the oil and water separation and desalination processes, contaminants may be removed from produced water. This produced water may also be treated and converted into reuse quality for beneficial purposes, such as agricultural, rangeland and grassland restoration, site remediation, landscape watering, or water for oil field use. Presently, there are no clear-cut laws and regulations in the United States dealing with the beneficial use of produced water.

The vast amounts of produced water along with natural gas is not only an issue in Texas, but in other states as well. Another uprising concern in the industry is the production of coal bed methane (CBM) along with water production, as found in Wyoming. According to the Bureau of Land management and the Powder River Basin Council of 2002, the average production of a CBM well is 125,000 cubic feet per day of gas and 12 gallons per minute of water. This exceeds over 17, 280 gallons per well of produced water with extremely high disposal expenses that must be managed daily along with the gas production.

The environmental effects of water disposal is a critical issue in all states of the U.S. It is much better to address environmental concerns early in a program than to be confronted to angry landowners or other concerned public representatives.

There currently exists a need for alternate methods of managing oil and gas produced water. The technology to remove contaminants from the produced water and create a new water resource is available. By working with the Texas A&M Department of Rural Sociology, the Rangeland Ecology and Management Department, as well as the Petroleum Engineering Department at Texas A&M, we have found that there are no market mechanisms and incentives currently available to the oil and gas industry to treat their produced water and make it available as a commodity. Secondly, we have to make the general public, as well as the industry, become aware of the technologies available and the benefits of using this technology to create a new water resource.

The photograph shows a managed test plot at the Mason Wildlife Management Area in West Texas. Agri-scientists use these plots to evaluate native grasses development, soil characteristics, hydrology of rainfall events.

IV. State and National Stakeholder Agencies

State Agencies

In New York, our SWC contact is John Martin of the New York State Environmental Development Authority (NYSERDA). NYSERDA is one of the sponsors of this project and through John will work to facilitate a field demonstration if an opportunity arises. In addition, through the IOGCC I was able to meet Bradley J. Field, Director of the Department of Environmental Conservation, Division of Mineral Resources, I briefed Mr. Field and have provided both him and John Harmon, the Deputy Director, a summary of our A&M beneficial use project. Opportunities for beneficial use projects may be limited. On the other hand, any successful project demonstrations would provide these agencies with valuable information to aid in the consideration of a future project.

For beneficial use projects in Pennsylvania the appropriate contact is the Department of Environmental Protection, Pennsylvania Bureau of Oil & Gas Management. Mr. James E. Erb is the Director. I met with Mr. Erb at an IOGCC meeting and briefed him on the project and provided him with a summary of the A&M program. Note that any possible projects in Pennsylvania will have the benefit of Penn State personnel to partner with A&M and company engineers in planning and operations.

In Texas the Railroad Commission regulates oil and gas activities. Railroad Commission of Texas: The Energy Operations Division Director is Ronald L. Kitchens, phone 512/463-7068; fax 512/463-7000 Michael Williams, one of three Commissioners has personally endorsed the concept of beneficial use projects and is knowledgeable about the technology being offered by Texas A&M. His deputy who coordinates the A&M projects is Bryndan Wright ((512) 463-7145). Texas offers the most opportunity for beneficial use projects. With the backing of the Chairman of the RRC, and the presence of A&M research centers throughout the state, any company interested in a project will have ample assistance.

In Oklahoma the agency responsible for oil and gas regulation is the Oklahoma Corporation Commission Oklahoma Corporation Commission: A good contact at the OCC is Michael L Decker, Deputy General Counsel ((405) 521-4258. He is involved with produced water discharge projects in Oklahoma and is working to draft new guidelines for beneficial use projects. Also in Oklahoma, the state Marginal Well Commission, a member of the SWC serves as a clearing house of key issues affecting independents. It is likely that a beneficial use project will be able to obtain permits necessary to implement any sound program.

A shortcut to all of these key individuals is provided by the A&M Fresh Water Resource Recovery Center is to use the contact information in our companion document that lists individual names, agency and contact information for each of the Stripper Well Consortium states.

National Agencies

As stated earlier, issues related to produced water management in individual states may also fall within the jurisdiction of state departments of environmental quality. One way to access the agency in a particular is through the EPA web site gateway at http://www.epa.gov/epapages/statelocal/envrolst.htm. These can give contact information necessary to begin the permitting process.

A national association that addresses state produced water issues in the Groundwater Protection Council http://www.gwpc.org. The GWPC is a national association of state ground water and underground injection control agencies that work to promote the protection and conservation of ground water resources for beneficial uses. Recognizing that fresh water recovered from oil field produced water will come in contact with ground water, the GWPC has established committees to address theses issues. As stated in their mission declaration, The Ground Water Protection Council provides a forum for stakeholder communication and research in order to improve governments' role in the protection and conservation of ground water."

One of the agencies that represent state interests is the Interstate Oil & Gas Compact Commission (IOGCC). This group represents the governors of **37 states** -- 30 members and seven associate states -- that produce virtually all the domestic oil and natural gas in the United States. The organization was established by the governors in 1935 and is among the oldest and largest interstate compacts in the nation.

The IOGCC assists states in addressing such issues as -- maximizing domestic oil and natural gas production, minimizing the waste of irreplaceable natural resources, and protecting human and environmental health -- through sound regulatory practices. It serves as the governors' collective voice on oil and gas issues and advocates states' rights to govern the petroleum resources within their borders. Regulatory coordination and government efficiency are among the IOGCC's long-standing interests.

Because of its unique structure, the IOGCC offers a highly effective forum for government, industry, environmentalists and others to share information and viewpoints, allowing members to take a proactive approach to dealing with emerging technologies and environmental issues. The organization is known internationally for significant contributions to oil and natural gas regulation and conservation practices.

The Internet link to IOGCC is http://www.iogcc.state.ok.us/. Anyone interested in can go to the site and select their state to link to regulatory agency responsible for oil and gas issues and to get contact information for their state's representatives.

A shortcut to all of these key individuals is provided by the A&M Fresh Water Resource Recovery Center is to use the contact information in our companion document that lists individual names, agency and contact information for each of the Stripper Well Consortium states.

V. Coordination to Effect Change in Regulations and Provide Benefits to the Environment

Role of the SWC

All of the states represented in the SWC will have various agencies with jurisdiction over new beneficial uses of produced water projects. It is necessary to coordinate efforts to streamline and simplify permitting so that such projects can be planned and implemented. The independent producer through the SWC has a strong voice in future directions of our agencies that govern oil and gas production in the U.S. and

Role of the Industry

The first step we as an industry have to take is to accept the fact that produced water can be a resource when properly treated and used for beneficial purposes. Once we see that we have a potential resource, we can work to set a value for the resource and to use it for projects to improve the environment, not harm it.

A&M's Role

Texas A&M is undertaking a number of steps to support fresh water resource recovery technology development. We are planning a new interdisciplinary program at the masters and doctorial level in water management. TWRI is our sponsor of our fresh water recovery and utilization program for oil field activity. And our group is available to assist others in creating new field demonstrations of technology that would further the cause of sustainable development related to fresh water resources.

VI. Results of SWC Project

We have reviewed the regulatory issues that a producer would encounter when planning a produced water resource recovery program. This final report summarizes the existing policies of state and federal agencies and recommends development of an approved program for re-use of water. The recommended program includes establishing a dialog with the local community and the regulatory agencies prior to planning a project. To facilitate new projects, Texas A&M offers its services at no cost to companies considering a project. Following are components of this research that can be used to help plan projects.

Contact List Database

A working contact list has been created for members of the SWC and will be maintained for the next six months. The list contains names of those individuals at agencies we have contacted. The database contains contact information on state and national officials, water treatment companies, and individuals involved with these types of programs nation-wide. Our complete database is included in the **Appendix** following this report.

Program Changes in Southwest U.S.

As a result of several meetings with the Texas Railroad Commission, our group has successfully gained its support in this project. Chairman Michael L. Williams of the TRRC visited Texas A&M endorsing our produced water research program[10]. Chairman Williams committed to help the project along by reviewing the state's regulations governing the reuse of treated oilfield produced water and determining what changes can be made to increase water availability. Williams has also pledged to help find funding for this particular program and to encourage oil and gas producers in Texas to support field demonstration. A copy of the letter of support from Chairman Williams and the Texas Railroad Commission is included in the URL listed in reference 10.

Program Changes in Eastern U. S.

In the Eastern U.S. where water is not as critical an issue, regulatory changes will be more gradual. The best way to effect change will be to find examples of successful projects that exemplify good science and careful operation. It is recommended that the SWC continue to be active in this area and serve as a spokesman for the independent producer whose livelihood is at stake.

A Prototype Program

VII. Roadmap to Acceptance: Recommendations for Further Work

There are five critical steps that need to be taken to demonstrate that oil field produced water has value and can be used for beneficial purposes.

Five Step Check List

For every field operation the operator must address the following:

1. Identify the resource. Where is the produced water coming from? How regular is the volume produced? How much water is being produced? How difficult is it to remove the contamination from the brine? What volume of "reject" water is produced along with the fresh water? How long will the waste stream be produced? These are some of the basic questions to be addressed by the operator. It is also important to identify a use for the resource so that the proper process design and monitoring program can be selected early in the design of the project. These questions need to be addressed in an organized and complete manner. We recommend that further work be done to organize the steps necessary to identify resources and estimate costs of recovering fresh water from that resource.

2. Engage the local community and the regulatory agencies. What can be done with the produced water? Do individuals in the area have a need for the fresh water? Is there a question about the environmental impact of the project? This type of the size of the treatment facility be of sufficient capacity to supply the water needed for a project. Consider the potential impact on the community –both positive and negative. We recommend that future field demonstrations of fresh water recovery include an industry-community dialog

3. Plan a project that is compatible with the environment and offers value to all stakeholders. Enlist the regulatory agencies. Learn the agency contacts for your area and show by example that a well-designed program will be beneficial to the area not a liability.

4. Demonstrate the program and monitor results. Field operations are a must if realistic determinations of cost and efficiency are to be demonstrated. Accurate monitoring of field operations will not only provide documentation of the correct operating practices but will also provide information that can be used for subsequent projects in other areas. For example, each of the test sites and the control sites of our Texas A&M beneficial use projects will be monitored for the growth of plant life and the presence of wildlife. A biochemical monitoring program will be established using state of the art DNA biotyping. Using results from the sampling program over an extended time period, tests the hypothesis that no environmental effects will be observed between the fresh water augmented sites and the treated produced water sites.

5. Report results. It will be imperative that field operations be described fully. Even if results are disappointing, test results from field operations are critical to improving design of treatment units and in changing operating practices.

Project Assistance Service Offered by Texas A&M

Any company willing to undertake a field demonstration of the use of fresh water resources from produced brine can contact us at Texas A&M. We will work, at no cost, to assist in creating field demonstrations. If A&M technology is requested we will work with your company to get supplemental funding from state or federal governmental agencies.

A&M Future Activities

Texas A&M University, through the Department of Petroleum Engineering is planning field demonstrations of the fresh water recovery process in a number of locations. The SWC will be asked to fund one of the field demonstrations in 2003 and 2004. In addition, we are working with partners who are providing pre-treatment technology crucial to oil field brine treatment. The Department’s oil field brine treatment program is a part of a University wide effort to address water management, fresh water resource recovery and beneficial use of water resources in a comprehensive, multi-disciplinary program. A new Masters and Doctoral academic program is being planned for the spring 2004 academic year. Simultaneously a campus wide research program is being designed to take advantage of our portable water treatment technology expertise. These resources are available to independent operators through the SWC.

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3. Hamid, S. and Yeo, W. N.: "Effluent Water Quality Improvement" paper SPE 27316 presented at the 1994 Second International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production held Jakarta, Indonesia, 25-27 January.
4. Garland, E. M.: "Produced Water in the North Sea: A Threat for the Environment or a Threat for the Industry?" paper SPE 46706 presented at the 1998 SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production held in Caracas, Venezuela, 7–10 June.
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7. Daza, D. S. *et al*.: "Environmental Land-Use for Hydrocarbon Exploration and Exploitation in Colombia" paper SPE 61281 presented at the 2000 SPE International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production held in Stavanger, Norway, 26–28 June.
8. Department of Petroleum Engineering GPRI (http://www.gpri.org), September 30, 2002
9. Texas Water Resources Institute http://www.twri.tamu.edu August 2002.
10. GPRI/A&M Fresh water Resource Recovery Project Letter of Endorsement from Chairman of Texas Railroad Commission. URL http://pumpjack.tamu.edu/gpri/facilities-process/projects/conversion-brine-fresh/rrc-letter.jpg

Environmental & Regulatory Issues with Recycled Oil Field Produced Water

- David B. Burnett GPRI
- Department of Petroleum Engineering
- Texas A&M University
- Faculty Group: Fresh Water Resource Technology
- 979 845 2274
- http://www.gpri.org

Presentation Based on Final Report

Stripper Well Consortium Meeting, November 12, 2002

Fresh Water Resource Technology

- Co Sponsoring Agencies
  - Texas Water Resources Institute (TWRI)
    - *Texas A&M Initiative for Water Management Resources Technology in Oil & Gas Production*
  - Stripper Well Consortium (SWC)
    - *Environmental & Regulatory Issues with Recycled Oil Field Produced Water*
  - New York State Environmental Development Agency (NYSERDA)
    - *Co-sponsor with SWC*
  - Ground Water Protection Council (GWPC)
    - *Ensuring protection of ground water resources from contamination*
- Industry Partner
  - Global Petroleum Research Institute (GPRI)
- Governmental Agency
  - Texas Railroad Commission Chairman Michael Williams

Does Produced Water have Value?

- Can the water be treated economically?
  - Impurities removed
  - Salinity removed
  - It's a lot easier than refining crude oil
- What can the water be used for?
  - Agriculture, watershed augmentation
  - Landscaping, Livestock Watering
  - Artificial Wetlands, Habitat Restoration
  - Rangeland Recovery
- Is the water environmentally safe? What Permits are Needed?
- Is there a method that will allow the water's value to be realized?
  - Sell or trade the water
  - Recover the cost of treatment
  - Tax Incentive to help rural sustainability

Proving that Produced Water is a Resource & not a Pollutant

- Step 1:
  - Designing Water Treatment to achieve acceptable fresh water quality.
- Step 2:
  - Developing a Water Reuse Program to utilize the water in beneficial manner.
- Step 3:
  - Monitoring to Ensure Environment is not harmed. Working to Change Laws and Limitations
- Step 4:
  - Realizing Water as Value for the Community

The Four "Big Steps" to A Successful Project

- Step 1: StepBrine Desalination Process 1
  - Water Treatment to remove contamination and desalinate the brine
- Step 2:
  - Regulatory Reform to encourage projects to utilize the water in beneficial manner. A&M SWC Project Step 2
- Step 3: Step 3
  - Monitoring to Ensure Environment is not harmed.
- Step 4: Step 4
  - Realizing Water as Value for the Community

Objectives of A&M SWC Project

To identify the constraints to oil and gas production caused by inappropriate environmental and regulatory requirement and

Identify the regulatory agencies and *areas of overlapping regulations or conflicting regulation*

To act as a change agent and work with appropriate agencies to write new guideline

To establish a program to modify the regulatory practices

To report to the consortium on the progress of the program.

To provide a focal point for a coordinated effort to effect change.

Stripper Well Consortium Project Deliverables

Reports and Briefings on current regulatory practices in Eastern U.S. (West Virginia, Pennsylvania, and New York) and in Western U.S. (Texas, Oklahoma, New Mexico, Wyoming).

Progress reports and briefings on communications with regulatory agencies.

Reports and briefings to describe a program to modify the regulatory practices

Delivery of a Directory of Regulatory Information for the benefit of members of SWC. A&M will maintain and update the Directory.

Results of the SWC Project

- Created Collaboration of Experts in Technology for On Site Water Treatment and Conversion to Fresh Water.
- Designed hypothetical field project and demonstrated use of the technology to recover fresh water from produced brine.
- Addressed the permitting process required to implement field project.
- Planned implementation of the new technology in field applications.
- Obtained endorsements of regulatory officials to work to get program to field operations.

Produced Water Processing & Re-Use: Regulatory Issues

- Federal Clean Water Standards apply to any waters discharged from Oil & Gas Operations
  - oil field produced brines contain hazardous chemicals
  - In Texas, no standards have been established for the treatment of produced brines.
  - Oversight responsibilities lie with different departments within EPA
  - No standards have been established for monitoring.
  - Finally, the public perceives produced water as a pollutant, not a resource.

Summary of EPA Water Regulations

- Underground Injection
  - Stewardship Shared by State and Federal Agencies
  - Advisory Group: GWPC (Ground Water Protection Council)
- Surface Use
  - Driven by Western States Coal Bed Methane (CBM) Programs

References:
U.S. EPA Handbooks (www.epa.gov/safewater
GWPC Handbook (ALL Consulting Inc., Tulsa OK.)

EPA Derived Resouces and Action Programs

- State Generated Source Water Assessments
- State Drinking Water Funds
- Wetland Protection Programs
- Source Water Petition Program
- Water Conservation Planning Programs
- Source Water Protection Program
- State Underground Injection Program

EPA Underground Injection Control Programs

State Controlled Programs

New Mexico, Texas, West Virginia, Wyoming

Joint State/EPA Programs

Colorado, Indiana

Federal Programs

Pennsylvania, New York, Virginia

www.epa.gov/safewater

State of Texas Oil Field Cleanup Program

- Six on-going reclamation projects have been identified.
- Salt water intrusion into fresh water resources indicates that there is an opportunity to intervenes, recovery fresh water on site and reduce the volume of salt water that must be hauled away.
- EPA regulations apply to these projects with the production of oil and gas because the project is protecting drinking water sources.

Planning for Permits – All States

- Recommendations
  1. Adhere to National Standards for Clean Water
  2. Plan for public discourse
  3. Identify Key Issues and Address them
  4. Establish independent Auditing Function
  5. Use the Precepts of Sustainable Development in Project Development.

Permits for Field Project: Texas

- RRC Land Treatment Permit – Current Restrictions:
  - Isolated from Ground Water
  - Not subject to flooding
  - Not subjected to erosion
  - Minimize release of pollutants to off-site water, lands or air.
- Texas Natural Resources Codes
  - Announcements in Newspaper –"Commercial Surface Disposal Facility Permit".
  - Public Meeting (subject to Commission's requirements)
- Liability
  - Not defined.

SWC Contact List: Categories

Name and Current Position

Organization

Location

Specialized Interests

Contact Information

Total contact list (10.01.02)= 281 entries

Contact List: Agencies and People

Academic Programs - 55

Texas A&M, U. of Tulsa, New Mexico Tech

Government Agencies and Contacts -95

BLM, DOE, EPA, USGS

Industry Consultants -21

Vendors - 20

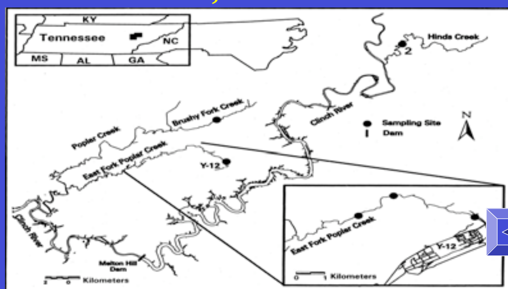
Oil & Gas Operations - 91

Total contact list (10.01.02)= 281 entries

Environmental Monitoring

- Measuring the Impact of the use of recycled oil field produced water on rangeland, wildlife, and habitats.
- Analytical testing of input and output water from modules.
- Baseline monitoring program of the environment
- Measurement of rate of habitat restoration.
- Environmental toxicology oversight of program
- Ultimate goal is to show recycled, produced water is not harmful to the environment and does not cause a buildup of harmful chemicals in wildlife.

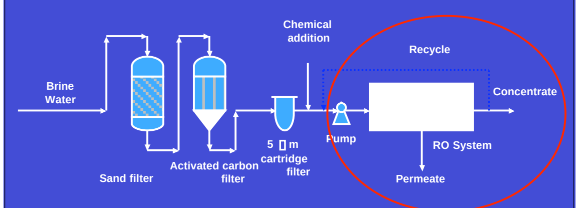
Example: Environmental Monitoring Site, Tennessee



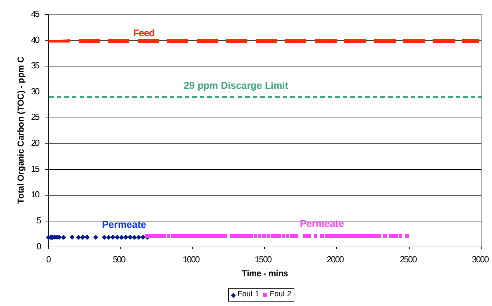
"Recommended Covenants for Produced Water Re-use"

1. Plan Project to improve environment, not just to comply with permits.
2. Seek project development from local communities
3. Look for economic market incentives to repay the extra cost of going beyond environmental compliance.

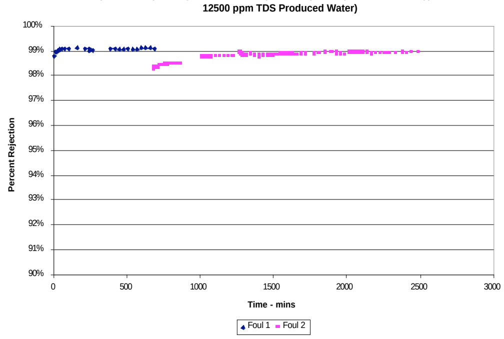
Brine Desalination Process



Total Organic Carbon (TOC) vs Time - Fouling Test for the Selected Membrane J
(Selected Operating Pressure = 550 psi and Operating Flow Rate = 10 gpm, 12500 ppm TDS Produced Water)



Percent Salt (TDS) Rejection vs. Time for Fouling Test for the Selected Membrane J
(Selected Operating Pressure = 550 psi and Operating Flow Rate = 10 gpm, 12500 ppm TDS Produced Water)



Produced Brine: Before and After Samples

Prod. Water Flow Rate	14000 gpd (9.72 gpm)								6000 gpd (9.72 gpm)							
Treated Water (Permeate) Flow Rate	7000 gpd (4.86 gpm)								3000 gpd (2.08 gpm)							
Total Capital Investment	95,000 $								75,000 $							
TOC before Organoclay	30 ppmC				80 ppmC				30 ppmC				80 ppmC			
Unit Life (years)	3	5	7	10	3	5	7	10	3	5	7	10	3	5	7	10
Cap[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]50 0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]00 7	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Operation Cost ($/gal perm.)	0.0074	0.0074	0.0074	0.0074	0.0107	0.0107	0.0107	0.0107	0.0086	0.0086	0.0086	0.0086	0.0119	0.0119	0.0119	0.0119
Total Water Cost ($/gal perm.)	***0.0198***	***0.0148***	***0.0127***	***0.0111***	***0.0231***	***0.0182***	***0.0161***	***0.0145***	***0.0314***	***0.0223***	***0.0184***	***0.0155***	***0.0348***	***0.0256***	***0.0217***	***0.0188***
Capital Cost ($/bbl perm.)	0.5205	0.3123	0.2231	0.1562	0.5205	0.3123	0.2231	0.1562	0.9589	0.5753	0.4110	0.2877	0.9589	0.5753	0.4110	0.2877
Operation Cost ($/bbl perm.)	0.3109	0.3109	0.3109	0.3109	0.4511	0.4511	0.4511	0.4511	0.3614	0.3614	0.3614	0.3614	0.5016	0.5016	0.5016	0.5016
Total Water Cost ($/bbl perm.)	***0.8315***	***0.6233***	***0.5340***	***0.4671***	***0.9717***	***0.7635***	***0.6742***	***0.6073***	***1.3203***	***0.9368***	***0.7724***	***0.6491***	***1.4605***	***1.0770***	***0.9126***	***0.7893***

Total Water Cost (7,000 gpd)
($/gal fresh water.) ***0.02***
($/bbl fresh water) 0.83

Total Water Cost (3,000 gpd)
($/gal fresh water.) ***0.03***
($/bbl fresh water) 1.32

Portable filtration unit donated to Texas A&M by Koch Micromembrane Filtration Services Inc.

Step 1

Step 4: Realizing Water to Value for the Community

1. Creation of a Community- Industry Dialog
2. Developing a model for water use and its value to the community.
3. Identifying Incentives for Producers to Treat Water and Provide it for Community Needs

Rangeland and Habitat Restoration using Rainfall Augmentation

Yates Ranch and Pecos River

Rangeland and Habitat Restoration using Rainfall Augmentation

Mason Wildlife Management Area Test Plot

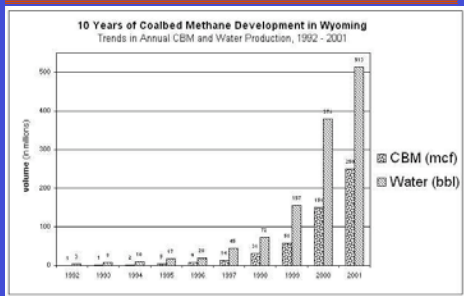
Rangeland & Grassland Rehabilitation

Texas A&M Agriculture Extension Service and Research has long offered special expertise in rangeland management.

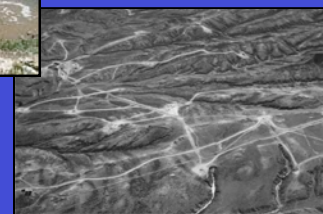
Microenvironment Creation for Site Remediation:

- **2 to 3 acre sites used for field demonstrations**
- **1 inch water per month avg. for 8 months**
- **Decreasing EC soil readings to less than 40**
- **Reestablishing salt grass seedlings**
- **Providing nutrients for wildlife and natural grass reestablishment.**

Water Production from CBM Development in Wyoming



BLM Rangeland at Risk: Powder River Basin



Step 4: Intervention for Rural Community Development

TRAVERSE CITY - U.S. Rep. David Bonior would boost the economy and protect the environment at the same time if he were elected governor, he told an environmental Group Wednesday. (**January 17, 2002**)
He touched on several environmental issues of concern to this region, including the South Fox Island land swap, slant drilling for natural gas under the Great Lakes, commercial bottling of groundwater and developmental sprawl.

Also, the number of water bottling plants is growing in Michigan and said they should be limited.
"They suck up water from our aquifer," he said. "We're losing the aquifer water we need to have an agricultural economy."

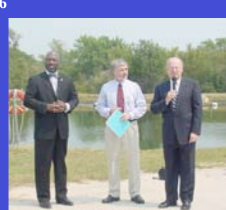
Future Activity – A&M Produced Water Treatment Program

- **Firm up Industry Participation in produced water treatment program**
- **Finalize module design and performance specifications.**
- **Select first field treatment site**
- **Create research program in sensor technology adaptable to automated, remote field operations.**

Harold Vance Department of Petroleum Eng.
Texas A&M University

Global Petroleum Research Institute
Texas Engineering Experiment Station
College Station, Texas 77843-3116

Thank You!



Advanced Decline Curve Modeling for Stripper Well Production Analysis

during the Period 05/15/2001 to 11/30/2002

By

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Abstract

This report documents work performed under the named contracts. Software has been developed to allow the user to evaluate gas well production data using advanced decline curve techniques. Such techniques include exponential and hyperbolic analysis, use of variable compressibility type curve and multi-layer completion effects. Results of such analyses include production forecasting and estimation of well/reservoir properties such as formation permeability, stimulation effectiveness and drainage area.

The software has been validated by comparison of software analysis results for 16 type wells that were also rigorously analyzed using reservoir simulation techniques.

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Executive Summary

Successful stripper well production requires careful attention to cost control – a requirement that extends to engineering and geologic evaluations of a stripper well's potential for remediation or production improvement. So, techniques the operator may apply in order to evaluate stripper wells in a fast, simple and reliable manner will be superior to those that do not.

In order to meet this need, Advanced Resources International's (ARI) advanced decline curve program (*METEOR*), which is designed specifically for low permeability, multiple completion gas wells, was refined to enable the operator to analyze stripper gas wells for the purposes of well remediation, recompletion or drilling options in stripper production areas. An executable copy of the *METEOR* software is included with this report for 2001 members of the Stripper Well Consortium, qualifying New York State operators and the Gas Technology Institute. *METEOR* was used to type curve match production data from a variety of stripper gas test wells that represented both geographical and reservoir diversity throughout the Appalachian Basin. To provide a basis of comparison for the type curve matching results for the test wells, ARI also conducted a rigorous history matching effort for each test well in the study, using ARI's reservoir simulation software, *COMET2*. The simulation results provided permeability, skin factor, drainage area and estimated recovery values for comparison to those results generated by the *METEOR* production type curve analysis software.

- With few exceptions, the single and multi layer type curve match results were able to replicate the results from the more detailed simulation history matching. From predetermined permeability values, *METEOR* was able to reasonably predict drainage area and cumulative recovery values for one and two layer completions.

- For desorption controlled reservoirs, *METEOR* will over predict drainage area values due to the presence of adsorbed gas in the shale or coal layer. To more properly account for the adsorbed gas-in-place, the reservoir's estimated porosity should be increased to provide an equivalent reservoir pore volume. Permeability and recovery values were similar to those derived from computer simulation.

- Since the *METEOR* type curve software is based on numerical formulations for fractures of infinite conductivity, differences in equivalent skin factor between simulator and type curve techniques are apparent. However, the results did reveal that well stimulated layers tended to have large fracture half-lengths while poorly stimulated zones had much smaller half-lengths. Future versions of *METEOR* should include formation damage curves within the transient portion of the type curve to improve the early time match. This would allow *METEOR* to model fracture cleanup or damage more effectively.

- *METEOR* software assumes a constant bottom hole flowing pressure for each match period. This is normally a reasonable assumption for low permeability gas wells.

However, some wells, such as the Area 16 study well, had significant long-term variation in flowing pressure. The inclusion of a rate normalization technique could further improve the accuracy of the software.

- Permeability values for the Devonian Shale (Cleveland and Lower Huron members) are fairly consistent for Areas 1 through 6 (Kentucky), ranging from 2 to 8 micro-darcies. Permeability for the Devonian Shale in Area 9 (Virginia), however, appears to be much higher (25 micro-darcies). Berea Sand permeability values appear to be much better than those determined in the Devonian Shale for Areas 1 through 6, ranging from 3 to 78 micro-darcies. Permeability estimates for the Whirlpool sand (0.10 to 0.50 md) are greater than that for the Grimsby sand (0.02 to 0.14 md). Skin factors determined during the history matching process indicate the study wells are generally very well stimulated, ranging from 0 to –4.6 for the individual reservoirs.

- Overall, well drainage areas for study wells 1 through 11 were found to be reasonable and are estimated to range from about 14 to 93 acres. Based on the data provided for the individual areas, nominal well spacing appears to be significantly larger than the history match derived drainage area, suggesting there is considerable merit to investigating more optimum well spacing scenarios. For study wells 12 through 16, drainage area estimates for the Grimsby sand were found to be small, with all but one less than 20 acres, while Whirlpool completions tended to drain areas larger than 40 acres. However, information is incomplete regarding offset well development.

- Predicted recovery efficiency values for the conventional gas reservoirs (Berea Sand, Big Injun, Big Lime, Weir, etc.) were generally much better than those for the Devonian Shale reservoirs. Because of the nature of desorption controlled reservoirs, the desorption (gas-release) process is more efficient when there is interference from offset production wells. This decreases reservoir pressure more quickly and accelerates the gas release from the shale layers.

- Even with small well spacing, recovery efficiency was very low for areas 1 and 7 due to the small permeability values, suggesting that optimum well spacing may be a function of reservoir permeability. This behavior is also apparent for the shale reservoirs, as the recovery efficiency values for Layer 2 in Area 9 are considerably greater (76% to 92%) than those experienced in Areas 1 through 6 (5% to 45%).

CHAPTER 1
Feature Upgrades and Program Modifications to *METEOR*

Introduction

The rapid analysis of produced gas volumes can be a valuable tool in evaluating the performance of low productivity (stripper) gas wells. However, in many areas around the United States, these stripper gas wells are completed in multiple reservoirs, which often complicates production analysis methodologies. Under a New York State Energy Research Development Authority (NYSERDA) program[1], Advanced Resources International, Inc. developed a layered-no-crossflow production type curve analysis program (*METEOR*) specifically for use with commingled completions. While this program offered the capability to perform a detailed two-layer production type curve analysis, and generated permeability, stimulation, drainage area and recovery estimates for each layer, the software itself was rather modest and lacked several features that would enhance its usability.

As a result, ARI has performed a multitude of software upgrades to the original, beta-version of *METEOR*, including but not limited to:

- Aarps-type hyperbolic production type curves
- Variable compressibility production type curves
- Calculation of permeability, fracture half-length, drainage area, estimated ultimate recovery, average reservoir pressure, and match quality coefficients
- Workover and restart options
- Improved plotting to include oil, water and pressure data
- Compatible data import/export
- Printing and reporting features
- Mapping interface to display results in x-y format
- Users guide

New Features/Modifications

Data Input and Storage: *METEOR* has been constructed to work with a variety of input file types. These file types include IHS format (*.98c), text formats (*.asc, *.csv, *.prn and *.txt) and Microsoft Excel format (*.xls). In addition, *METEOR* can incorporate input data obtained from reserve determination software such as ARIES and OGRE.

This production data is read into a Microsoft Access database hierarchy, which the user names, for rapid retrieval of production data. In addition, all type curve match derived data is also stored in the database, enabling *METEOR* to save and "remember" match results.

New Program Interface: **Figure 1** depicts a screen capture of the basic user interface. Drop-down menus are available across the upper left hand corner of the program to enable the user to manipulate the project file and print reports (*File*), edit the graph window (*Edit*), toggle the current view (*View*), import or edit the data (*Database*), perform type curve matching (*Analysis*), toggle and control the mapping features (*Maps*), cascade or tile the open windows (*Window*) and provide additional help (*Help*). Below the menu, six toolbar functions are provided to enable the user to rapidly open a new project, open an existing file, copy to the clipboard, print, provide help and initiate type curve matching.

If the project consists of more than one well, a list of well names can be accessed from the drop-down menu at the left of the screen. Selecting a well name will display a production chart to the right and information for the well in fields below the well name drop-down menu. In addition to the chart tab, data and map tabs are provided to allow the analyst to inspect the data and, if x and y coordinates are available for each well in the project, to view the distribution of wells and their cumulative and projected recoveries. Supplementary map views in *JPEG* or *PCX* formats, such as elevation and formation thickness, can be readily imported to the project and subsequently viewed.

Hyberbolic Type Curve Matching: *METEOR* provides the capability of estimating reservoir, completion and production parameters such as permeability, fracture half-length, drainage area and estimated ultimate recovery for one or two productive layers. To determine these parameters, the analyst must invoke the type curve analysis mode via the analysis menu or the type curve matching toolbar button, which brings up the type curve interface window (**Figure 2**).

This new window contains the means for matching the gas production data to the *METEOR* hydraulically fractured type curve. The user has been provided with a number of options at his disposal to conduct the matching process. Perhaps the most important of which are the mechanisms for moving the data in order to align it with the type curve. To align the data and type curve within the match window, the user can translate the data by clicking the appropriate arrow on the *Shift Points* four-way arrow button in the lower right corner of the window. This button shifts the data points up, down, left and right, relative to the type curve, to enable the user to match the data to the type curve. Immediately to the left of the button is a movement sensitivity slider bar, which allows fine to coarse movements on a scale of one (fine) to ten (coarse). In addition, selecting the *Move* toolbar button and then using the mouse to click and drag the data will also transfer the data.

For refinement of the match, the user has the option to view the data with various multiple point smoothing routines (*Smoothing*), with semi-log plots (*Graph*), with zooming (*Zoom* toolbar button) and, located in the upper right hand corner of the window, with a least squares difference in the y-direction for measuring match quality (*Results*). The shape of the type curve can be modified by selecting the appropriate drainage stem (*Xe/Xf*) or the Aarps hyperbolic decline exponent (*Hyper. Exponent (b)*).

As the analyst manipulates the match, *METEOR* dynamically updates the match parameters, Qmatch and Tmatch, as well as the results, for permeability (*k*), fracture half-length (*Xf*), drainage area (*A*), original gas in place (*OGIP*) and estimated ultimate recovery (*EUR*).

Besides creating a match of the data, the analyst must also input the gross (if two layers) or single-layer reservoir parameters into the database by either selecting *User Input* button or by clicking in the *Data Info* area. Within this window the user has the ability to alter reservoir data such as thickness, porosity and pressure. Once the desired estimates are entered, *METEOR* will dynamically update the results in the type curve matching window as well as in the database, provided the save (*Save*) toolbar button is depressed. As with any computer process, frequent use of the Save button is encouraged.

The gas properties can be reviewed by selecting the appropriate toolbar buttons to show the gas viscosity (*Viscosity*), z-factor (*Zfactr*) and pseudopressure, or real gas potential, (*Pseudo*) for the gas described in the user input dialogue. When selected, a graphical representation of the property on the y-axis is plotted against the x-axis range of zero to reservoir pressure.

In addition to viewing gas and PVT data, the user can export the forecasted gas production and average reservoir pressures by selecting the *Write CSV* toolbar button at the top of the window. If the variable compressibility option has been enabled (discussed later), the rate forecast for that option is included in the *CSV* formatted text file.

Restarts: *METEOR* has the capability to handle changes in operating conditions, well workovers and re-stimulations through the use of a unique restart option. To utilize the restart option, the user must first define the restart (by placing a "1" in the *Period* text box) and input the restarts beginning (*Start*) and ending (*End*) months. Subsequent restarts will be activated by incrementing the value in the *Period* text box.

The user can then re-intialize the data set in the *METEOR* type curve matching window by placing the number that appears to the right of the *Period* text box in the *Pseudo TStart* text box. As the user enters the value, the type curve restart will re-initialize, allowing the user to assess the impact of the restart period. Also, *METEOR* will automatically decrement the value in the *Pseudo TStart* text box by a value of one. Type curve matching of the restart data can then be carried out including any desired changes in bottomhole flowing pressure, reservoir pressure, thickness, etc.

Variable Compressibility Type Curve Matching: In addition to the single-layer hyperbolic type curve matching option, the analyst has the ability to estimate the impact of pressure depletion on PVT properties such as gas compressibility and gas viscosity in low permeability gas reservoirs. This effect generally manifests itself following the departure from the infinite acting portion of the type cure (or when a boundary is encountered). From a practical standpoint, this behavior is manifested as a deviation from the decline stem (selected match *Xe/Xf*) with the variable compressibility curve often crossing over the other curves to the right.

To activate this feature, the user must select the Compressibility Option check box. A heavy green line then appears, allowing the user to refine the match, as shown in **Figure 3**. To do so, the user must typically decrease the selected *Xe/Xf* match point until the variable compressibility line passes through the production data.

<u>Multi-layer Hyperbolic Type Curve Matching:</u> If the analysis is to consider multiple completions, the multi-layer matching can be performed. This must be done following a composite (single) layer match. **Figure 4** depicts the multi-layer matching window. For this analysis, the composite match (red line) is used as the basis for the matching the individual layers.

Individual layer parameters, such as thickness, porosity and water saturation must then be entered for each layer. The analyst then has the freedom to alter layer permeability, fracture half-length and drainage area for each of the two completions. Once initial values have been entered, the *PLOT* button can be depressed to review the results.

Depicted are the individual layer production estimates, their summation and the composite match result. Should the layer summation and the composite match overlay, good agreement has been achieved between the single and multi-layer analyses. If they diverge, the analyst is then free to adjust any values to achieve a quality match.

Reference

1. "Advanced Decline Curve Model for Layered, No-Crossflow Completions in the Medina/Whirlpool Gas Wells of New York.", NYSERDA contract no. 5007-ERTER-ER-99, 1999.

CHAPTER 2
Reservoir Simulation of Study Wells

Introduction

In order to assess the new software features, detailed reservoir simulation history matching was carried out on a series of study wells. History matching results were then compared to the results obtained from production type curve matching using the improved *METEOR* software.

The following discussion outlines the reservoir simulation results using *COMET2* to history match Equitable Production Company's (Equitable) eleven study wells selected from areas in Kentucky, West Virginia and Virginia and Belden & Blake Corporation's five study wells located in Pennsylvania. **Table 1** contains the results in tabular form.

Study Area Discussion

<u>*Equitable Production Company Study Areas:*</u>

Area 1 Study Well – Located in Pike County, Kentucky, this well was originally completed in the Berea sandstone from 3,273 to 3,336 feet and the Devonian Shale from 3,411 to 4,337 feet in December 1991. From the geophysical well logs, reservoir properties were determined to be thickness values of 50 and 184 feet, porosity values of 7.6% and 1% (estimated) and water saturation values of 36.2% and 30% (estimated) for the Berea sand and Devonian Shale, respectively. In mid April 2000, the well was recompleted in the Big Lime formation from 2,412 to 2,574 feet. Since this study is concerned with at most two layers, the Big Lime recompletion was not considered in this exercise.

For those layer properties still not quantified, such as reservoir pressure and shale desorption isotherm values, Equitable personnel familiar with these production areas provided estimates of initial pressure, as well as the next 5 areas, at 0.25 psia/foot. For the Devonian Shale's desorption isotherm, a literature review identified a viable isotherm (**Figure 5**)[1], which was used for all Shale formations in this study.

Figure 6 depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia). Note that the gain in production rate at approximately 3,000 days represents the completion of the Big Lime formation. To obtain this high quality match, available wellhead data was used as the production simulation constraint. Resultant values for formation permeability were determined to be 0.003 and 0.002 md for the Berea sand and the Devonian Shale, respectively, while drainage area for each of the two layers was determined to be about 14 acres.

Initial values for the well's skin factor were –4.4 and –4.3 for the Berea sand and Devonian Shale. However, following approximately 800 days of production history, the averaged (monthly) daily production rate instantaneously drops from over 20 Mcfd to about 4 Mcfd, with no accompanying explanation in the historical data files. To model this effect, the skin

Table 1 – Simulation Results

Area	Formation	Date	Depth Top ft	Depth Bottom ft	Perfs Top ft	Perfs Bottom ft	Thickness ft	Porosity %	Sw %	Match Parameters Pr psi	Perm md	Initial Skin	Final Skin	Area acres	20-Year Cum MMCF
1	Berea	Dec-91	3,262	3,342	3,273	3,336	50	7.2%	36.2%	815	0.003	-4.40	6.00	14.4	16.0
	Devonian Shale	Dec-91	3,342	4,440	3,411	4,337	184	1.0%	30.0%	920	0.002	-4.30	6.00	14.4	40.6
2	Berea	Feb-90	3,760	3,872	3,777	3,861	55	6.8%	46.0%	954	0.009	-4.30	-4.30	13.5	62.0
	Devonian Shale	Feb-90	3,872	4,805	3,876	4,706	214	1.0%	30.0%	1,072	0.003	-4.30	-4.30	13.5	174.0
3	Berea	Feb-93	3,210	3,330	3,316	3,330	34	7.2%	33.0%	818	0.078	-4.75	-4.75	57.6	191.0
	Brown Shale	Feb-93	3,330	3,870	3,330	3,864	187	1.0%	30.0%	899	0.005	-4.50	-4.50	57.6	271.0
4	Berea	Sep-98	2,750	2,800	2,798	2,800	6	4.9%	45.3%	694	0.030	-3.50	-3.50	22.5	7.0
	Devonian Shale	Sep-98	2,800	3,243	2,800	3,243	177	1.0%	30.0%	755	0.008	-3.50	-3.50	22.5	181.0
5	Cleveland	Jul-91	3,248		3,286	3,336	56	1.0%	40.0%	828	0.009	-4.35	-4.35	64.8	99.0
	Lower Huron	Jul-91		3,572	3,502	3,562	59	1.0%	40.0%	883	0.005	-4.35	-4.35	64.8	69.0
6	Berea	May-92	3,149	3,242		3,242	48	6.9%	28.5%	799	0.021	-3.60	-3.60	21.6	84.0
	Devonian Shale	May-92	3,242	4,212		4,096	224	1.0%	30.0%	917	0.013	-3.40	-3.40	21.6	349.0
7	Big Injun	Aug-81	2,126	2,135	2,132	2,144	12	15.7%	26.0%	398	0.031	-4.80	-4.70	72.9	95.0
8	Big Lime	Sep-98			1,498	1,575	23	10.3%	16.3%	107	0.430	-1.00	-1.00	22.5	16.0
	Big Injun/U.Weir	Sep-98			1,717	1,765	28	10.8%	32.3%	119	0.400	0.00	0.00	22.5	19.0
9	Big Lime/ Weir	Jun-97			3,570	3,778	41	4.5%	65.0%	566	0.020	-4.60	-4.00	72.9	41.4
	Devonian Shale	Jun-97			4,041	4,858	284	1.0%	30.0%	683	0.025	-4.60	-4.00	72.9	209.7
10	Big Injun	Dec-97			2,653	2,673	20	4.7%	42.9%	494	0.150	-2.00	-2.00	72.3	53.9
	Weir	Dec-97			2,718	2,809	40	4.2%	47.4%	512	0.080	-2.00	-2.00	93.0	77.0
11	Big Lime/ U, M & L Weir	Jul-98	2,365	2,924	2,386	2,925	75	6.2%	43.9%	493	0.113	-3.00	-3.00	51.6	138.0
	G Stray - Be/ Gordon	Jul-98	3,186	3,412	3,214	3,406	31	6.0%	53.6%	611	0.080	-3.00	-3.00	24.8	34.3
12	Whirlpool	Dec-92	5,491	5,505	5,494	5,498	14	10.0%	30%	1,340	0.50	-2.72	2.50	64.4	221.0
13	Grimsby	May-98	5,315	5,348	5,277	5,344	33	6.0%	30%	700	0.13	-4.50	-4.50	15.2	36.3
	Whirlpool	Aug-93	5,420	5,434	5,423	5,427	14	14.0%	30%	850	0.29	-4.00	4.50	44.6	97.5
14	Grimsby	May-98	5,093	5,180			57	5.0%	30%	800	0.04	-3.70	-3.70	14.0	48.5
	Whirlpool	Feb-85	5,208	5,220	5,212	5,216	12	10.0%	30%	1,600	0.50	-3.80	0.50	98.0	350.4
15	Grimsby	Dec-92	5,497	5,579	5,497	5,549	52	7.0%	30%	1,200	0.14	-4.00	3.00	51.0	309.9
	Whirlpool	Dec-92	5,599	5,613	5,604	5,609	14	8.0%	30%	1,200	0.45	-4.00	3.00	51.0	110.8
16	Grimsby	Dec-88	5,168	5,269	5,179		57	5.0%	30%	1,247	0.02	-3.00	-3.00	14.0	84.2
	Whirlpool	Dec-88	5,294	5,303		5,301	9	7.0%	30%	1,250	0.10	-3.00	-3.00	14.0	21.5

factor was altered from –4.4 and –4.3 to +6 in each layer. For the duration of the history match, the skin remained +6 for each respective layer.

Area 2 Study Well **–** On February 1, 1990 this well, in Pike County, Kentucky, was completed in the Berea sand from 3,760 to 3,872 feet and in the Devonian Shale from 3,872 to 4,805 feet. From the provided geophysical well logs, thickness and porosity for the Berea sand were estimated to be 55 feet and 6.8%, respectively. Thickness and porosity for the Devonian Shale were estimated to be 214 feet and 1.0%, respectively. The initial pressures used were 1,072 psia for the Berea and 954 psia for the Devonian Shale. A pressure gradient of 0.25 psig/ft was used for both layers.

To match the production history of the well, an average wellhead pressure of 53 psia was used as the production constraint. Final match parameters for the Devonian Shale and Berea sand are permeability values of 0.009 and 0.0025 md and a drainage area of 13.5 acres, for both layers. The skin factor value used was -4.3 for both layers. **Figure 7** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia).

Area 3 Study Well **–** On February 1, 1993 this well, in Pike County, Kentucky, was completed in the Berea sand from 3,210 to 3,330 feet and in the Brown Shale from 3,330 to 3,870 feet. From the provided geophysical well logs, thickness and porosity for the Berea sand were estimated to be 34 feet and 7.2%, respectively. Thickness and porosity for the Brown Shale were estimated to be 187 feet and 1.0%, respectively. The initial pressures used were 817 psia for the Berea and 899 psia for the Brown Shale. A pressure gradient of 0.25 psig/ft was used for both layers.

To match the production history of the well, an average wellhead pressure of 42 psia was used as the production constraint. Final match parameters for the Brown Shale and Berea sand are permeability values of 0.078 and 0.005 md and drainage areas of 57.6 and 90 acres, respectively. The skin factors used were -4.75 for the Brown Shale layer and -4.50 for the Berea layer. **Figure 8** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia).

Area 4 Study Well **–** On September 1, 1998 this well, in Knott County, Kentucky, was completed in the Berea sand from 2,750 to 2,800 feet and in the Devonian Shale from 2,800 to 3,243 feet. From the provided geophysical well logs, thickness and porosity for the Berea sand were estimated to be 6 feet and 4.9%, respectively. Thickness and porosity for the Devonian Shale were estimated to be 177 feet and 1.0%, respectively. The initial pressures used were 694 psia for the Berea and 795 psia for the Devonian Shale. A pressure gradient of 0.25 psig/ft was used for both layers.

To match the production history of the well, an average wellhead pressure of 60 psia was used as the production constraint. Final match parameters for the Devonian Shale and Berea sand are permeability values of 0.008 and 0.030 md and a drainage area of 22.5 acres, for both layers. The skin factor values used were –4.75 for the Berea and –4.50 for the Devonian Shale. **Figure 9** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia). At 650 days, an increase in gas productivity is seen, which later returns to the normal decline trend. At this time, the cause of the increase is not known.

Area 5 Study Well – On July 1, 1991 this well, in Perry County, Kentucky, was completed in the Devonian Shale from 3,248 to 3,572 feet. This shale completion was comprised of the Cleveland, perforated from 3,286 to 3,336 feet, and the Lower Huron, perforated from 3,502 to 3,562 feet. From the provided geophysical well logs, pay thickness for the Lower Huron pay zone was estimated to be 59 feet while the pay thickness of the Cleveland shale was estimated to be 56 feet. Porosity was assumed to be 1.0% for each layer. The initial pressures used were 828 psia for the Lower Huron and 883 psia for the Cleveland. A pressure gradient of 0.25 psig/ft was used for both layers.

To match the production history of the well, an average bottomhole pressure of 30 psia was used as the production constraint. Final match parameters were permeability values of 0.009 md and 0.005 md, respectively, over a drainage area of 64.8 acres for both the Lower Huron and Cleveland shale formations. The skin factor used for both layers was -4.35. **Figure 10** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia).

Area 6 Study Well – On May 1, 1992 this well, in Pike County, Kentucky, was dually completed in the Berea sand from 3,149 to 3,242 feet and in the Brown Shale from 3,242 to 4,212 feet. From the provided geophysical well logs, thickness and porosity for the Berea sand was estimated to be 48 feet and 6.9%, respectively. Thickness for the Devonian Shale was estimated to be 177 feet. The initial pressures used were 799 psia for the Berea and 917 psia for the Devonian Shale. A pressure gradient of 0.25 psig/ft was used for both layers.

To match the production history of the well, an average bottomhole pressure of 55 psia was used as the production constraint. Final match parameters were permeability values of 0.021 and 0.013 md over a drainage area of 21.6 acres for both the Brown Shale and Berea sand. The skin factors used were -3.6 for the Brown Shale and -3.4 for the Berea sand. **Figure 11** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia).

Area 7 Study Well – On August 1, 1981 this well, in Fayette County, West Virginia, was completed in the Big Injun from 2,126 to 2,135 feet. From the provided geophysical well logs, thickness for the Big Injun pay zone was estimated to be 12 feet and porosity was 15.7%. The initial pressure value was estimated to be 398 psia, using a pressure gradient of 0.25 psig/ft.

To match the production history of the well, an average wellhead pressure of 40 psia was used as the production constraint. The final permeability value was 0.031 md over a drainage area of 72.9 acres. The initial skin factor was –4.8, finishing at –4.7 at the end of production history. **Figure 12** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia).

Area 8 Study Well – On September 30, 1998 this well, in Nicholas County, West Virginia, was completed in three zones. The Big Lime was completed from 1,498 to 1,575 feet, the Big Injun from 1,717 to 1,735 feet and the Upper Weir from 1,755 to 1,765 feet. In order to simulate a dual completion, the Big Injun and Upper Weir formations were combined and the porosity and thickness values were averaged. From the provided geophysical well logs, thickness and porosity for the Big Lime were estimated to be 23 feet and 10.3%, respectively. Porosity and thickness averages for the Big Injun/Upper Weir were 10.8% and 28 feet, respectively. The initial pressures used were 107 psia for the Big Lime and 120 psia for the Big Injun/Upper Weir. A pressure gradient of 0.1 psig/ft was used for both layers.

To match the production history of the well, an average wellhead pressure of 30 psia was used as the production constraint. Final permeability values were 0.43 md for the Big Lime and 0.40 md for the Big Injun/Upper Weir layers over a drainage area of about 23 acres. The skin factors used were –1.0 for the Big Lime and 0.0 for the Big Injun/Upper Weir layers. **Figure 13** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead pressure (psia).

Area 9 Study Well – This well, located within Wise County, Virginia, was drilled and completed in four reservoirs in June of 1997. From top to bottom, the four horizons were the Big Lime, Weir, Cleveland shale and Lower Huron Shale. From the well's completion and geophysical data, total reservoir thickness, porosity and water saturation were determined for each zone. **Table 2** exhibits the log-derived reservoir data for the study well.

Table 2 – Log-Derived Reservoir Properties for Area 9

Zone 1							
Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
Big Lime			3,570	3,587	17.0	6.8%	63.7%

Zone 2							
Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
Weir			3,670	3,778	24.0	2.9%	123.4%

Zone 3							
Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
Clev Sh			4,041	4,502	178.0	1.0%	30.0%

Zone 4							
Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
L Huron Sh			4,752	4,858	106.0	1.0%	30.0%

Since at most only two intervals can be analyzed using ARI's *METEOR* production type curve software, the four discrete reservoirs were combined into a Big Lime/ Weir layer (layer one) and a Cleveland/ L Huron layer (layer two). While total thickness for the combined layers was an additive process, the porosity and water saturation data was thickness-averaged. The final petrophysical properties for layer one were a thickness of 41 feet, a porosity of 4.5% and a water saturation of 65% (estimated due to high Weir water saturation), while layer two's properties were a thickness of 284 feet, a porosity of 1.0% (assumed) and a water saturation of 30% (assumed).

An initial pressure gradient for this area was determined to be 0.15 psig/ft, which produced against an average wellhead pressure of 50 psia. Using the wellhead pressure as the production constraint for the history matching effort, a high-quality history match of cumulative gas and gas rate was achieved (**Figure 14**). From the match, permeability was determined to be 0.02 md and 0.025 md for layer one and two, respectively. Also, the skin factor and drainage areas for layer one and two were found to be –4.6, eroding to –4 after about 500 days, and 73 acres.

Area 10 Study Well – On December 31, 1997, this well, in Fayette County, West Virginia, was completed in the Big Injun from 2,653 to 2,673 feet and the Upper Weir from 2,718 to 2,809 feet. From the provided geophysical well logs, thickness and porosity for the Big Injun and Weir pay zones were estimated to be 20 feet and 4.7% as well as 40 feet and 4.2%, respectively. An initial bottomhole pressure gradient of 0.18 psig/ft was used to estimate reservoir pressure for each producing interval.

To match the production history of the well, an average bottomhole pressure of 65 psia was used as the production constraint. The final permeability values were 0.15 md and 0.08 md for the Big Injun and Weir formations. Drainage areas were modeled at 72 and 93 acres for the Big Injun and Weir sands, respectively. Skin was estimated at a -2.0 value for the duration of the simulation for each layer. **Figure 15** depicts the history match of cumulative gas production (Mcf) as well as gas rate (Mcfd) and wellhead production pressure (psia).

Area 11 Study Well – This well was completed and placed on production in July of 1998 in Fayette County, West Virginia. Five zones were perforated and stimulated from the Big Lime to the Gordon sand, where production was commingled. From the well's completion and geophysical data, total reservoir thickness, porosity and water saturation were determined for each zone. **Table 3** exhibits the log-derived reservoir data for the study well.

For this study, however, at most only two intervals can be analyzed using ARI's *METEOR* production type curve software. So, the five discrete reservoirs were combined into a Big Lime/ Middle, Upper Weir/ Lower Weir layer (layer one) and a Gordon Stray – Berea/ Gordon layer (layer two). While total thickness for the combined layers was an additive process, the porosity and water saturation data was thickness-averaged. The final petrophysical properties for layer one were a thickness of 75 feet, a porosity of 6.2% and a

Table 3 – Log-Derived Reservoir Properties for Area 11

Zone 1							
Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
Big Lime	2,365	2,669	2,386	2,396	10.0	5.8%	36.3%

Zone 2							
Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
M/U Weir	2,774	2,841	2,782	2,830	55.0	6.3%	43.4%

Zone 3							
Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
Lower Weir	2,914	2,924	2,917	2,925	10.0	6.1%	54.7%

Zone 4							
Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
G Stray/BE	3,186	3,222	3,214	3,283	17.0	6.2%	53.2%

Zone 5							
Formation	Top	Bottom	Perf Top	Perf Btm	Thickness	Porosity	Sw
Gordon	3,390	3,412	3,396	3,406	14.0	5.8%	54.0%

water saturation of 44%, while layer two's properties were a thickness of 31 feet, a porosity of 6.0% and a water saturation of 54%.

An initial pressure gradient for this area was determined to be 0.18 psig/ft, which produced against an average wellhead pressure of 55 psia. Using the wellhead pressure as the production constraint for the history matching effort, a high-quality history match of cumulative gas and gas rate was achieved (**Figure 16**). From the match, permeability was determined to be 0.11 md and 0.08 md for layer one and two, respectively. Also, the skin factor and drainage areas for layer one and two were found to be –3 and –3 as well as 51.6 and 24.8 acres.

<u>*Belden & Blake Corporation Study Wells:*</u>

Area 12 Study Well – This well was completed in the Whirlpool sandstone in December of 1992 from 5,494 to 5,498 feet. From the provided geophysical well logs, gross thickness and porosity for the pay zone were estimated to be 14 feet and 10%, respectively. Further, since almost no water was produced from this well, the mobile water saturation was set at 5%, with an irreducible saturation of 25%. Initial reservoir pressure was estimated to be 1,340 psi from a 48-hour post-frac pressure buildup (1,175 psi).

To match the production history of the well, casing pressure was used as the production constraint. Since the initial twelve months of casing pressure data declined from nearly 1,200 psi to about 350 psi, values for each month were input. Following the first year, four time periods where the casing pressure behaved similarly were identified. In these periods, the casing pressure values were averaged to obtain the simulation input value.

Final match parameters were a permeability of 0.5 md over a drainage area of 64.4 acres. Skin factor was found to vary during the well's producing life as:

1. +12 for the first month
2. –2.7 until 608 days
3. +2.0 until 1,491 days
4. +2.5 until the end of history

While the +12 skin value for month one was used to account for post-fracture treatment cleanup, the fracture stimulation was able to achieve a negative skin factor, thereafter. From approximately 500 days of production (see history match plot of TW #1), the simulated gas rate no longer matches history and the skin factor is adjusted to a damaged condition from 608 days to the end of history. It is not understood what may have happened to the stimulated nature of the well. However, a slightly positive skin is required to match the later time history. The history match is depicted in **Figure 17**.

Area 13 Study Well – This well was completed in the Whirlpool sand from 5,422 to 5,427 feet in August of 1993 and then recompleted in Grimsby sand from 5,277 to 5,344 feet in May of 1998. From the provided geophysical well logs, gross thickness and porosity for the pay zone were estimated to be 14.0 ft and 14% for the Whirlpool completion and 33.0 ft and 6% for the Grimsby recompletion. Further, since almost no water was produced from this well, the mobile water saturation was set at 5%, with an irreducible saturation of 25%. Initial reservoir pressure was estimated to be 850 psi for the Whirlpool sand, based on the 48-hour post-frac pressure buildup (745 psi).

To match the production history of the well, casing pressure was used as the production constraint and was input accordingly. Following the first year, two regions where the casing pressure behaved similarly were identified. In these regions, the casing pressure values were averaged to obtain the simulation input value. The well's initial skin factor was –4, which was then gradually degraded in order to make the history match, ultimately reaching a value of +4.5. Permeability was determined to be 0.3 md over a drainage area of 44.6 acres.

In 1998, the well was recompleted by adding the Grimsby formation. Without completion and pressure information for the zone, it was assumed that the gross interval was perforated, stimulated and completed. Gross properties for the Grimsby sand from geophysical logs, indicated that 33 feet of sand with a porosity of 6% was available from 5,277 feet to 5,348 feet. In order to obtain a post-1998 match, it was further assumed that the Whirlpool sand would still be contributing production. Therefore, the match variables were determined to be initial reservoir pressure, permeability and skin for the Grimsby sand.

Final history match parameters for the Grimsby were determined to be a bottomhole pressure of 700 psi, a permeability of 0.13 md, a skin factor of -4.5 and a drainage area of 15.2 acres (based on the assumed completion and match pressure). The history match is depicted in **Figure 18**.

Area 14 Study Well – This well was provided to ARI as a Grimsby sand completion that was later recompleted in the Whirlpool sand. A review of the completion and geophysical log information provided to ARI indicated that the well is in actuality initially completed in the Whirlpool sand from 5,212 to 5,216 feet in February of 1985. From the provided geophysical well logs, gross thickness and porosity for the pay zone were estimated to be 12 feet and 10%, respectively. Further, since almost no water was produced from this well, the mobile water saturation was set at 5%, with an irreducible saturation of 25%. Initial reservoir pressure was estimated to be 1,600 psi from a 48-hour post-frac pressure buildup (1,400 psi).

To match the production history of the well, casing pressure was used as the production constraint and was input accordingly. Following the first year, eight time periods where the casing pressure behaved similarly were identified. In these periods, the casing pressure values were averaged to obtain the simulation input value.

The increasing production for the first 500 days was not adequately explained through the input of the wellhead pressure. The well's skin factor was therefore varied to achieve a history match of the production data. It was theorized that during this time, the hydraulic fracture treatment slowly cleaned up and improved the well from an initial skin factor of +7.0 to –3.8 (at 500 days). During the next four thousand days, the skin factor was gradually reduced to +0.5 to obtain a match, using a permeability of 0.5 md and a drainage area of 98 acres.

In 1998, the well was recompleted by adding the Grimsby formation. Without completion and pressure information for the zone, it was assumed that the gross interval was perforated, stimulated and completed. Gross properties for the Grimsby sand from geophysical logs, indicated that 57 feet of sand with a porosity of 5% was available from 5,093 feet to 5,180 feet. In order to obtain a post-1998 match, it was further assumed that the Whirlpool sand would still be contributing production. Therefore, the match variables were determined to be initial reservoir pressure, permeability and skin for the Grimsby sand.

Final history match parameters for the Grimsby were determined to be a bottomhole pressure of 800 psi, a permeability of 0.04 md, a skin factor of -3.7 and a drainage area of 14.0 acres (based on the assumed completion and match pressure). The history match is depicted in **Figure 19**.

Area 15 Study Well – This well was completed in January of 1992 in the Grimsby sand, from 5,497 to 5,579 feet, and the Whirlpool sand, from 5,599 to 5,613 feet. From the provided geophysical logs, gross sand thickness and porosity for these intervals were determined to be 52 feet and 7% for the Grimsby sand and 14 feet and 8% for the Whirlpool sand, respectively. Additionally, the 48-hour post-frac surface pressure was reported as 1,055 psi.

The simulation was conducted using wellhead casing pressure as the simulation input in order to match historical gas production. The history matching results yielded a permeability of 0.14 md for the Grimsby sand and 0.45 md for the Whirlpool sand. Skin factor and drainage areas were modeled using degrading skin values and 51 acres for each layer, respectively. Bottomhole pressure was found to be 1,200 psi for the Grimsby sand and 1,200 psi for the Whirlpool sand. The history match is depicted in **Figure 20**.

Area 16 Study Well – This well was completed in December of 1988 in the Grimsby sand, from 5,168 to 5,269 feet, and the Whirlpool sand, from 5,294 to 5,303 feet. From the provided geophysical logs, gross sand thickness and porosity for these intervals were determined to be 57 feet and 5% for the Grimsby sand and 9 feet and 7% for the Whirlpool sand, respectively. Additionally, the 18-hour post-frac surface pressure was reported as 1,050 psi.

A review of the available pressure data (historical casing, tubing and line pressures were available) showed that a full pressure history was unavailable for this well. Further, while the first four study wells used casing pressure as the input parameter, the tubing pressure for this well varied significantly from the casing pressure. This is most likely due to the use of surfactant as a water lifting mechanism. So, the well was matched using gas rate as the simulation input in order to match the available tubing pressure data.

Figure 21 depicts the difference between available wellhead casing and tubing pressure as well as the history matched wellhead pressure. The character of the simulated response is quite good, matching the increasing casing pressures observed from about January 1993 to October of 1995.

The history matching results yielded a permeability of 0.018 md for the Grimsby sand and 0.10 md for the Whirlpool sand. Skin factor and drainage areas were modeled using –3 and 14 acres for each layer, respectively. Bottomhole pressure was found to be 1,247 psi for the Grimsby sand and 1,250 psi for the Whirlpool sand. The history match is depicted in **Figure 22.**

Conclusions

This study is wholly based on geologic, geographic and production data provided by Equitable and Belden & Blake to ARI. Although ARI has performed a detailed analysis of geophysical well logs and determined nominal drill spacing for each study area, ARI must rely on Equitable and Belden & Blake to verify the results of these analyses. Further, it is essential to point out that the results of these history match simulations and projections are susceptible to variations in the key input parameters of reservoir thickness and pressure drawdown (initial reservoir pressure less wellhead/ bottomhole production pressure).

Equitable Production Company Study Areas:

- Permeability values for the Devonian Shale (Cleveland and Lower Huron members) are fairly consistent for Areas 1 through 6 (Kentucky), ranging from 2 to 8 micro-darcies. Permeability for the Devonian Shale in Area 9 (Virginia), however, appears to be much higher (25 micro-darcies).

- Berea Sand permeability values appear to be much better than those determined in the Devonian Shale for Areas 1 through 6, ranging from 3 to 78 micro-darcies.

- Overall, estimated well drainage areas are reasonable and are estimated to range from about 14 to 93 acres.

- Skin factors used during the history matching process indicate the study wells are generally very well stimulated, ranging from 0 to –4.6 for the individual reservoirs.

- The pressure gradient (0.1 psig/ft) provided for Area 8 is the lowest value in the study, necessitating the highest permeability values (0.43 and 0.40 md) to match the production history.

- For those study wells completed later in pattern development, partial pressure depletion may not have been considered in the provided initial pressure gradients. This may lead to the determination of permeability and drainage areas values that are smaller than actual. This partial depletion effect is more pronounced for those study wells with smaller nominal well spacing values.

- Based on the provided data, nominal well spacing appears to be significantly larger than the history match derived drainage area, suggesting there is considerable merit to investigating more optimum well spacing scenarios.

Belden & Blake Corporation Study Wells:

- Permeability estimates for the Whirlpool sand (0.10 to 0.50 md) are greater than that for the Grimsby sand (0.02 to 0.14 md), which tends to agree with current perception.

- Drainage area estimates for the Grimsby sand were found to be small, with all but one less than 20 acres, while Whirlpool completions tended to drain areas larger than 40 acres. However, information is incomplete regarding offset well development.

- For the recompleted wells, the Whirlpool sand skin factors for the initial completions were modeled as degrading more rapidly than those of the later Grimsby completions. This may be an important observation concerning offset well drilling during the productive life of the initial completions as drainage areas for these Whirlpool intervals ranged from 45 to 98 acres. For the later Grimsby sand completions, the drainage areas were only 15 and 14 acres, respectively. If infill drilling is actually the cause of well performance and not degrading skin factors, then reduction in drainage area during the Whirlpool sand's producing life and not reduced (more positive) skin factors may better match the production history. This would also impact the remaining study wells.

Reference

1. Schettler, P. D., Parmely, C., "Physicochemical Properties of Methane Storage and Transport in Devonian Shale," 1991 Annual Technical Report, Gas Research Institute Contract No. 5085-213-1143.

CHAPTER 3
Multi-Layer Type Curve Matching of Study Wells and Software Verification

Introduction

With the simulation work completed, estimates of layer permeability, skin factor, drainage area and estimated ultimate recovery (**Table 1**) have been collected for each study well. These results were used as a baseline for comparison to and verification of the *METEOR* production type curve analysis software.

An important consideration when comparing the results of the simulation history matching to the production type curve matching is the presence of Devonian Shale reservoirs in some of the study well data sets. Since the Devonian Shale is a desorption-controlled reservoir (gas is adsorbed within the shale), input of the shale porosity will cause the type curve program to overestimate the drainage area required to produce the equivalent volume of gas. In those cases where shale layers are present, no attempt has been made to "gross-up" the shale porosity value to account for adsorbed gas. Therefore, results comparison wills be concerned with permeability, fracture half-length (skin factor) and 20-year ultimate recovery for those study wells containing shale-gas reservoirs.

Table 4 shows the results of the type curve matching, with restarts. The following is a discussion of the results for each area study well.

Results

<u>*Equitable Production Company Study Areas:*</u>

Area 1 – Since gas production declines dramatically at 27 months of production, a type-curve analysis restart was necessary to fully compare the simulation and type curve results. The late time increase in productivity due to the completion of a new layer in the well was not considered. **Figures 23** and **24** show the results of the single and multi layer type curve matching for the first 26 months of production. The character of the data is fairly consistent and follows the selected drainage stem (in red on **Figure 23**) very well. Input parameters for this single layer match are depicted on the bottom of **Figure 23**.

To analyze the discrete layers, a multi layer analysis was carried out (**Figure 24**). At the upper-left corner of the graphic, the commingled properties are shown from the single layer type curve match, which describe the well's idealized total recovery rate vs. time. This is also shown as the red line from **Figure 23**. Using the two other upper panels of the graphic, porosity, thickness, water saturation and Aarps decline exponent (b) can then be input for each of the two layers. Following data input, the permeability, fracture half-length and drainage area for each of the layers can then be input into the software.

Table 4 – Single and Multi Layer Type Curve Matching Results

	Commingled Match								Layer 1						Layer 2					
Area	Start month	Pi psia	Thick ft	b	Perm md	Xf ft	A acres	EUR MMcf	Thick ft	b	Perm md	Xf ft	A acres	EUR MMcf	Thick ft	b	Perm md	Xf ft	A acres	EUR MMcf
1		905	234	0.5	0.002	181	9	61	50	0.5	0.003	225	9	32	184	0.5	0.002	175	9	39
Restart	27	626	234	0.5	0.002	10	5	55	50	0.5	0.003	11	7	9	184	0.5	0.002	11	7	13
2		1,026	269	0.5	0.004	177	13	184	55	0.5	0.009	182	14	73	214	0.5	0.003	182	14	69
Restart	47	700	269	0.5	0.004	191	54	233	55	0.5	0.009	200	60	85	214	0.5	0.003	200	60	95
3		872	221	1.0	0.017	283	46	433	34	0.5	0.078	310	58	229	187	0.5	0.005	250	170	221
4		737	193	0.5	0.009	221	55	141	6	0.5	0.030	221	23	7	187	0.5	0.008	221	60	124
5		868	115	0.5	0.007	221	219	165	56	0.5	0.009	221	220	98	59	0.5	0.005	221	220	68
6		857	272	0.5	0.014	106	66	432	48	0.5	0.021	125	22	83	224	0.5	0.013	105	120	343
7		398	12						12	0.5	0.031	1,345	426	96						
Restart	59	330	12						12	0.5	0.031	231	69	96						
8		179	51	0.5	0.411	17	16	26	23	0.5	0.430	17	23	13	28	0.5	0.395	17	23	14
9		624	325	0.5	0.024	150	25	171	41	0.5	0.020	160	30	23	284	0.5	0.025	160	30	109
Restart	17	450	325	0.5	0.024	119	64	235	41	0.5	0.020	130	73	28	284	0.5	0.025	130	78	158
10		500	60	0.8	0.106	40	58	115	20	0.5	0.150	40	70	47	40	0.5	0.085	40	90	76
11		552	106	0.5	0.102	49	31	152	75	0.5	0.113	48	33	127	31	0.5	0.075	48	25	31
12		1,340	14						14	0.5	0.498	30	53	218						
13		850	14	0.5											14	0.5	0.291	95	30	109
Restart	57	650	47	0.8	0.181	129	12	111	33	0.5	0.130	105	10	25	14	0.5	0.298	105	32	82
14		939	12	0.0											12	0.0	0.493	73	194	380
Restart	150	700	69	0.5	0.120	34	15	380	57	0.5	0.040	40	14	37	12	0.5	0.502	40	15	28
15		1,200	66	0.5	0.204	29	49	407	52	0.5	0.140	29	51	369	14	0.5	0.444	29	51	174
16		1,250	66	0.5	0.031	27	15	102	57	0.5	0.020	27	15	88	9	0.5	0.103	27	15	35

Depressing *METEOR*'s plot button then creates a graphic of the predicted recovery from each layer (blue and yellow lines), their summation (orange line) and the idealized total recovery rates from the single layer match (red line). A match is achieved when the summation of layers 1 and 2 overlays the single layer match (**Figure 24**).

The restart period, from 27 months of production, was matched in the same manner. Key differences are the input of a new reservoir pressure (note the 626 psi input at the bottom of **Figure 25**) and the consideration of data only after 26 months.

The quality of the restart data was not particularly good for this study well as it appears to be gently inclining over this six year productive period. Nevertheless, a match was determined and a multi layer analysis was performed (**Figure 26**).

A comparison of the simulation and type curve results shows excellent agreement between permeability values, 0.003 md and 0.002 md for layers one and two, and cumulative recovery, nearly 57 MMscf as compared to either 61 or 55 MMscf for the type curve solutions. However, predicted drainage areas, 14.4 acres against 9 and 7 acres, were much lower than expected due to the presence of a shale layer. Simulated skin factors were found to be –4.4 and –4.3, declining to +6 in both layers, while the *METEOR* software predicted 225 and 175 feet of infinite conductivity fracture half-length (X_f), initially, and then 11 feet of fracture half-length for the restart period.

The differences in equivalent skin factor are not surprising as the *METEOR* software is based on numerical formulations for use with low permeability gas reservoirs. Hydraulic stimulations are assumed to create infinite conductivity fracture half-lengths. However, in these study well cases, the simulated stimulation response is nearly always less than the idealized infinite conductivity response (100 to several hundred feet) due to damage, suggesting the need for implementing damage curves within the transient portion (early time) of the type curve.

***Area 2* – Figures 27** and **28** depict the single and multi layer production type curve matches for the first 48 months of history. After 47 months of production, Area 2 also required a restart to match data following an extended period of shut-in. Average reservoir pressure was estimated to be 700 psia at this time based on reservoir voidage. **Figures 29** and **30** show the matches.

For the simulation work, this study well was anticipated to have permeability values of 0.009 and 0.003 md, skin factors of –4.3 and –4.3, drainage areas of 13.5 and 13.5 acres from Layers 1 and 2, respectively. 20-year recovery was expected to be 236 MMscf. Type curve results showed a good match with layer permeability values, the well was highly stimulated and large drainage areas, which were most likely due to the shale reservoir (Layer 2). In addition, recovery was estimated to be 233 MMcf.

Area 3 – An Aarps decline exponent of 1.0 was used to match the data for the commingled production stream. **Figure 31** depicts the effect on the type curve. The multi layer match is shown in **Figure 32**, using decline exponents of 0.5 for each layer. The results showed good agreement with permeability, fracture half-length and drainage area. As expected, the shale layer accounted for an area greater than that seen in the history matching. Simulation and type curve predicted recovery values were 462 MMcf and 433 MMcf, respectively.

Area 4 – Type curve matching results and graphics for Area for can be found in **Figures 33** and **34**. No restart period was required to characterize this study well's productive history. Although there was some scatter in the data, there was good agreement between type curve and simulation derived results. Layer 1 and 2 permeability values were determined to be 0.030 and 0.008 md for both cases, with highly stimulated (X_f of 220 ft and skin of –4.3) reservoirs. As a Devonian Shale layer was present, the type curve match area was considerably larger than the simulation predicted value – 60 to 22.5 acres – as expected. However, cumulative recover estimates were found to be 141 MMscf and 188 MMscf for each technique.

Area 5 – The Area 5 study well was completed in two portions of the Devonian Shale – the Cleveland and Lower Huron shale layers. Production data from this well was extremely high quality, leading to excellent single layer and multi layer matches (**Figures 35** and **36**). Permeability values were found to be 0.009 and 0.005 md, while fracturing indicated well-stimulated conditions (X_f of 220 ft). Estimated 20-year recoveries were almost identical for each layer, coming in at 99 and 66 MMscf for the simulation and 98 and 68 MMscf for the type curve match. Again, drainage area was over-predicted at 220 acres for each layer as compared to the simulation-derived value of 65 acres.

Area 6 – **Figures 37** and **38** show the single and multiple layer type curve matches for the Area 6 study well. The multiple layer type curve results again showed excellent agreement with those from the simulation work, with the only difference being the larger drainage area in layer 2 (shale).

Area 7 – The study well for Area 7 was completed in only the Big Injun formation. Since it was only a single completion, no multiple layer matching was performed. Further, a restart was needed to match the data from 59 months to the end of history due to a long-term shut-in of the well. Although the initial match (**Figure 39**) revealed a very long infinite conductivity fracture (1,345 feet) with an associated large drainage area, the well may still be in linear flow without encountering a reservoir or offset well boundary. The subsequent match of the restart data (**Figure 40**) resulted in a fracture half-length and drainage area (231 feet and 69 acres) that was comparable to the simulated results (-4.7 and 73 acres). Cumulative recovery was also found to be similar to the simulation results.

Area 8 – Since the simulation results indicated the skin factor to be near zero (neutral), type curve matching for the Area 8 study well could not fully replicate the simulation results due to the fact the type curves are designed for infinite conductivity fractures. Approximations were made, however, to greatly reduce the determined fracture lengths to small values (17 feet). As a result, good agreement with the simulation results were determined for permeability, drainage area and recovery for each of the two layers. **Figures 41** and **42** show the type curve matches.

***Area 9* – Figures 43** through **46** show the initial and restart type curve matches for this study well. The restart occurred following 16 months of production time. The initial match showed good agreement with permeability and indicated that the well was stimulated with a 160 ft fracture half-length. Drainage area was low due to the rapid decline seen in the data set.

The restart period also had good agreement with permeability. Additionally, a declining skin factor from the initial to the restart period (X_f of 150 to 119 ft) was seen, which agreed with the simulation case, and the drainage area was in better agreement as well. Total recovery was close between the simulation and type curve match results (251 MMcf to 235 MMcf). However, individual layers varied dramatically. This is due to the removal of the initial 16 months of production history from the computation of 20-year recovery values.

***Area 10* –** The results of the single and multi layer matching for the Area 10 study well were shown in **Figures 47** and **48**. The type curve results show good agreement with those derived from the simulation history matching. Permeability values were very close, skin factors, predicted at –2 for the simulation, were found to be 40 feet and drainage areas were within a few acres. As a result, layer recoveries were within a few MMscf from one another.

***Area 11* –** Type curve matching results were in agreement with the simulation results. **Figures 49** and **50** depict the type curve matches. Permeability and fracture half-lengths were found to compare favorably to the simulation results. However the drainage area determined for Layer 1 indicated an area (33 acres) less than the expected value of 52 acres. This discrepancy accounts for the 10 MMscf difference in Layer 1 20-year recovery.

Belden & Blake Corporation Study Areas:

***Area 12 Study Well* – Figure 51** shows the results of the single layer type curve match for this study well. Since the well was completed in only one layer (Grimsby sand), no multi layer matching was necessary. The type curve matching results compared favorably with the simulation history matches. Permeability was found to be 0.5 md, fracture half-length was about 31 feet and drainage area was determined to be 55 acres. 20-year recovery was estimated to be 218 MMscf, which was very close to the simulated result of 221 MMscf. Input parameters for this single layer match are depicted on the bottom of **Figure 52**.

Although the simulation history match estimated the skin factor to be –2.7, which is equivalent to an infinite conductivity fracture of about 5 feet in length, *METEOR* estimated the fracture length to be about 30 feet (-4.0). The differences in equivalent skin factor are not surprising as the *METEOR* software is based on the assumption of perfect transient behavior of infinite conductivity fracture half-lengths. However, in these study well cases, the reality is that the true stimulation response is nearly always less than the idealized infinite conductivity response (100 to several hundred feet) due to fracture face damage, long-term fracture cleanup and degradation, suggesting the need for implementing damage curves within the transient portion (early time) of the type curve.

Area 13 Study Well – Initially producing only from the Whirlpool Sand, the initial type curve match was conducted using the hyperbolic decline curves. **Figure 52** shows the resultant type curve match. Although the drainage area was slightly less than the history match value of 45 acres, the permeability and fracture half-length values showed good agreement with the simulation results.

Figures 53 and 54 depict the single and multi layer type curve matches for the restarted production period, following the addition of the Grimsby Sand at 57 cumulative months of production time. To match the character of the declining production, an Aarps decline exponent of 0.8 was selected to best match the data.

Along the top of the graphic, the commingled properties are shown from the single layer type curve match, which describe the well's idealized total recovery rate vs. time, also the red line from **Figure 53**. Porosity, thickness, water saturation and Aarps decline exponent (b) can then be input for each of the two layers. Following data input, the permeability, fracture half-length and drainage area for each of the layers can then be input into the software. To analyze the discrete layers, a multi layer analysis was carried out (**Figure 54**) following the single commingled analysis.

Depressing *METEOR*'s plot button then creates a graphic of the predicted recovery from each layer (blue and yellow lines), their summation (orange line) and the idealized total recovery rates from the single layer match (red line). A match is achieved when the summation of layers 1 and 2 overlays the single layer match (**Figure 54**).

A comparison of the simulation and type curve results shows good agreement between permeability values, 0.13 md and 0.29 md for layers one and two, and drainage area values, 10 and 32 acres. However, cumulative recovery and fracture half-length predictions were not as good.

Area 14 Study Well – Much like the previous study well, this well was also initially completed in the Whirlpool sand and later recompleted in the Grimsby Sand. **Figure 55** depicts the type curve match of Whirlpool production using *METEOR*'s hyperbolic decline analysis. Permeability, fracture half-length and recovery values matched reasonably well. However, drainage area was twice the simulation predicted value.

At 150 months of production, the Grimsby Sand was added to the production stream. **Figures 56 and 57** show the single and multi layer production type curve plots of the restart data. The multi layer match results for the restart period had good agreement with permeability. Additionally, a declining skin factor from the initial to the restart period (Xf of 73 to 40 ft) was seen, which agreed with the simulation case. The drainage areas were less than those predicted from the simulation case. However, the restart match does not have the capability of imposing a depleted reservoir pressure on the initial completion. So, an average pressure value was used, which may impact the volumetrics of a layer-by-layer examination. 20-year recovery values were about 380 MMscf as compared to the simulation-predicted value of about 410 MMscf.

***Area 15 Study Well* – Figures 58 and 59** show the single and multiple layer type curve matches for this study well. Estimated permeability and drainage area values were in good agreement with those values determined from the history match. Further, the small fracture half-length values concur with those simulation results indicating a strong initial skin factor (-4) declining to a damaged condition (+3).

***Area 16 Study Well* –** As with the previous study well, there was little contrast in a comparison of simulation and type curve matching results. **Figures 60 and 61** show the single and multi layer type curve matches for this study well. The overall quality of the data is quite good and it is shown in the strong match results. Permeability, fracture half-length (27 ft is equivalent to –3.8), drainage area and 20-year recovery values as determined by *METEOR* are all similar to those determined from simulation history matching.

Conclusions

Equitable Production Company Study Areas:

- With few exceptions, the single and multi layer type curve match results were able to replicate the results from the more detailed simulation history matching. From predetermined permeability values, *METEOR* was able to reasonably predict drainage area and cumulative recovery values for one and two layer completions, thus verifying calculation performance of the new software.

- For desorption controlled reservoirs, *METEOR* will over predict drainage area values due to the presence of adsorbed gas in the shale or coal layer. To more properly account for the adsorbed gas-in-place, the reservoir's estimated porosity should be increased. Permeability and recovery values were similar to those derived from computer simulation. For the reservoir conditions in this study, a typical porosity increase to match drainage area and skin factor was from 1% to 3.5%.

- Since the *METEOR* type curve software is based on numerical formulations for fractures of infinite conductivity, the differences in equivalent skin factor, between simulator and type curve, are not surprising. However, the results did reveal that well stimulated layers tended to have large fracture half-lengths while poorly stimulated zones had much smaller half-lengths. The inclusion of damage curves within the transient portion of the type curve would improve the early time match significantly, allowing *METEOR* to model fracture cleanup or damage more effectively.

Belden & Blake Corporation Study Areas:

- With few exceptions, the single and multi layer type curve match results were able to replicate the results from the more detailed simulation history matching. From predetermined permeability values, *METEOR* was able to reasonably predict drainage area and cumulative recovery values for one and two layer completions.

- Since the *METEOR* type curve software is based on numerical formulations for fractures of infinite conductivity, the differences in equivalent skin factor, between simulator and type curve, are not entirely surprising. However, the results did reveal that well stimulated layers tended to have large fracture half-lengths while poorly stimulated zones had much smaller half-lengths. The inclusion of damage curves within the transient portion of the type curve would improve the early time match significantly, allowing *METEOR* to model fracture cleanup or damage effectively.

- *METEOR* software assumes a constant bottom hole flowing pressure for each match period. This is normally a reasonable assumption for low permeability gas wells. However, some wells such as the Area 16 study well had significant long-term variation in flowing pressure. The inclusion of a rate normalization technique could further improve the accuracy of the software.

Appendix 1

METEOR v. 1.1 Help File

I. Getting Started with *METEOR v. 1.1*

A. About this help file
1. References to toolbar, menu and other control functions for the *METEOR* software are shown bold and italicized
2. A superscript 1 denotes unavailable, at the time, controls
3. A superscript 2 denotes a feature that is accessible from the production type curve analysis window

B. Compatible file types
1. *METEOR* saves files as *.mdb, which is a Microsoft Access database file
2. Data is importable in IHS format, which is *.98c. Data can be exported this way from P.I. Dwights software or downloaded from their website.
3. Other import options include text format (*.txt, *.csv, *.prn, *.asc) and Excel format (*.xls). However, for these formats, the production data must be in columnar formats. Example input files for text and Excel-based input have been included in the sample directory.

C. Creating and opening database files
1. To begin the production analysis, the user is first required to create a new project database (*.mdb) file. To do so, the user can select either the ***New Project*** toolbar button or by selecting ***File*** from the menu and then ***New***. Following the selection, a dialogue box, **figure 1**, will prompt the user to name, locate and save the new project.

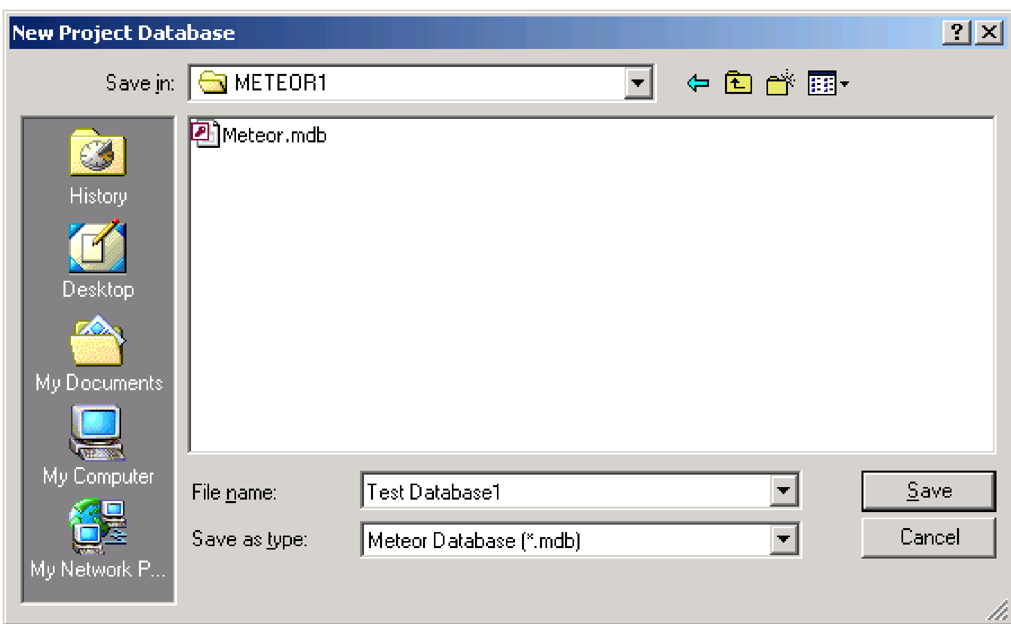

Figure 1 – New Project Database Dialog Box

2. Following the creation of the project, the user must populate the project with production data. A second dialogue box, **figure 2**, will prompt the user for the production data files to import, beginning within the directory the user created the project. Compatible file types were discussed in section B.

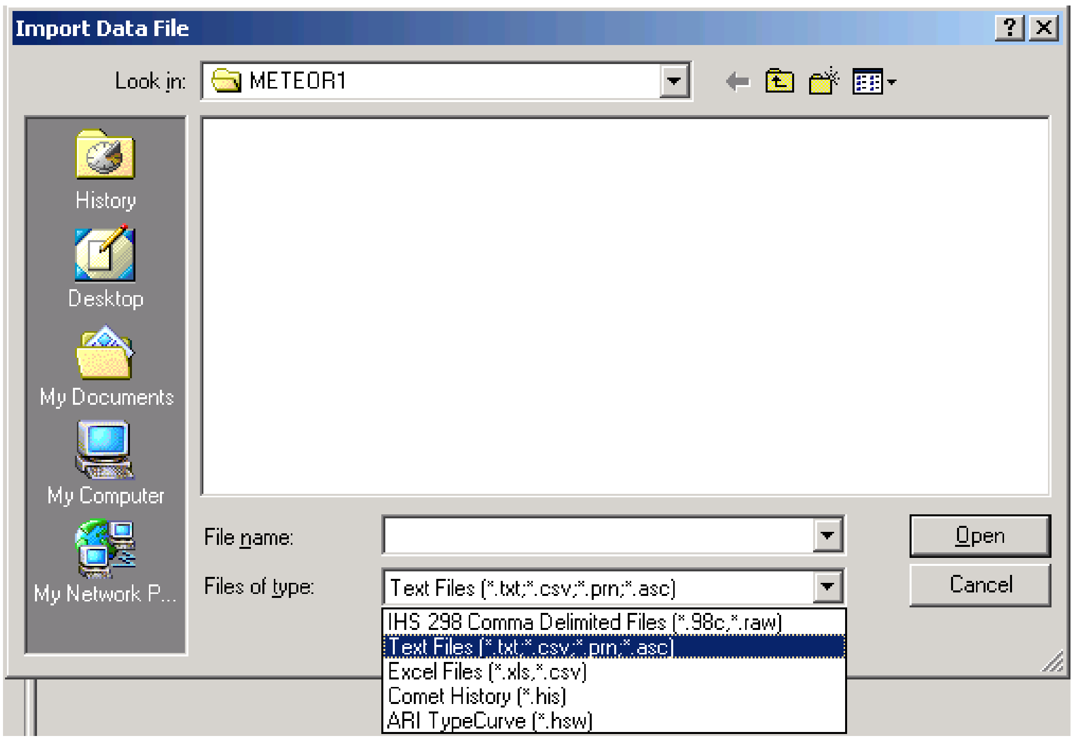

Figure 2 – Import Data File Dialog Box

3. To open an existing project the user can select ***File*** from the menu and then ***Open*** from the submenu or the user may choose to use the ***Open Project*** toolbar button. Each selection will bring up a dialogue box to allow the user to navigate to the directory containing the project. Select the relevant project and depress the ***Open*** button in the dialogue control.

D. Importing Production Data
   1. Importing IHS data files (*.98c, *.raw)
      a. Open or create a new *METEOR* Database (*.mdb)
      b. When prompted, indicate the IHS data file (*.98c) to input within the import data file dialogue box, making sure the appropriate types of file ***(*.98c, *.raw)*** have been selected at the bottom of the dialogue box. If necessary, navigate to the appropriate directory containing the *.98c file using the ***Look in*** drop-down box.

c. The import process is automatic and the user is ready to begin the production type curve matching process.

2. Importing Text Files (*.txt, *.csv, *.prn, *.asc)
    a. Open or create a new *METEOR* Database (*.mdb)
    b. When prompted, indicate the text file (*.txt) to input within the import data file dialogue box, making sure the appropriate types of file ***(*.txt, *.csv, *.prn, *.asc)*** have been selected at the bottom of the dialogue box. If necessary, navigate to the appropriate directory containing the *.txt file using the ***Look in*** drop-down box.
    c. Select the ***Production*** database table for the import destination. This can be accomplished by using the drop-down menu to select "Production" and clicking the ***OK*** button. See **figure 3**.

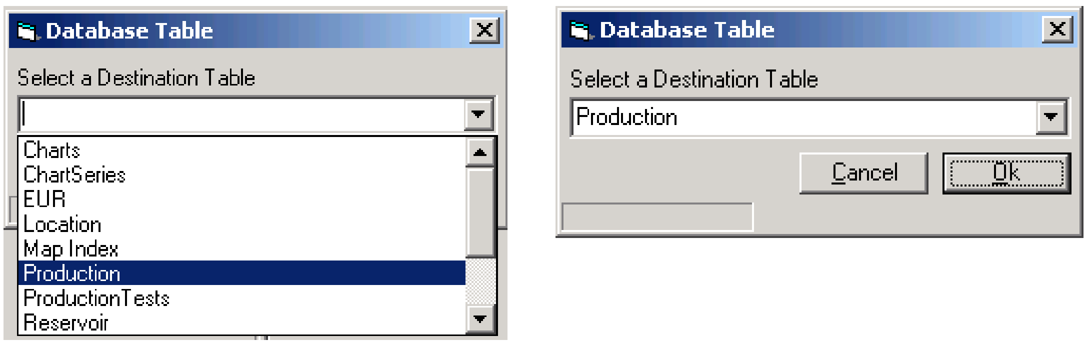

Figure 3 – Import Destination Table Dialog Box

    d. The ***Import Text File*** dialogue wizard will appear, **figure 4**.

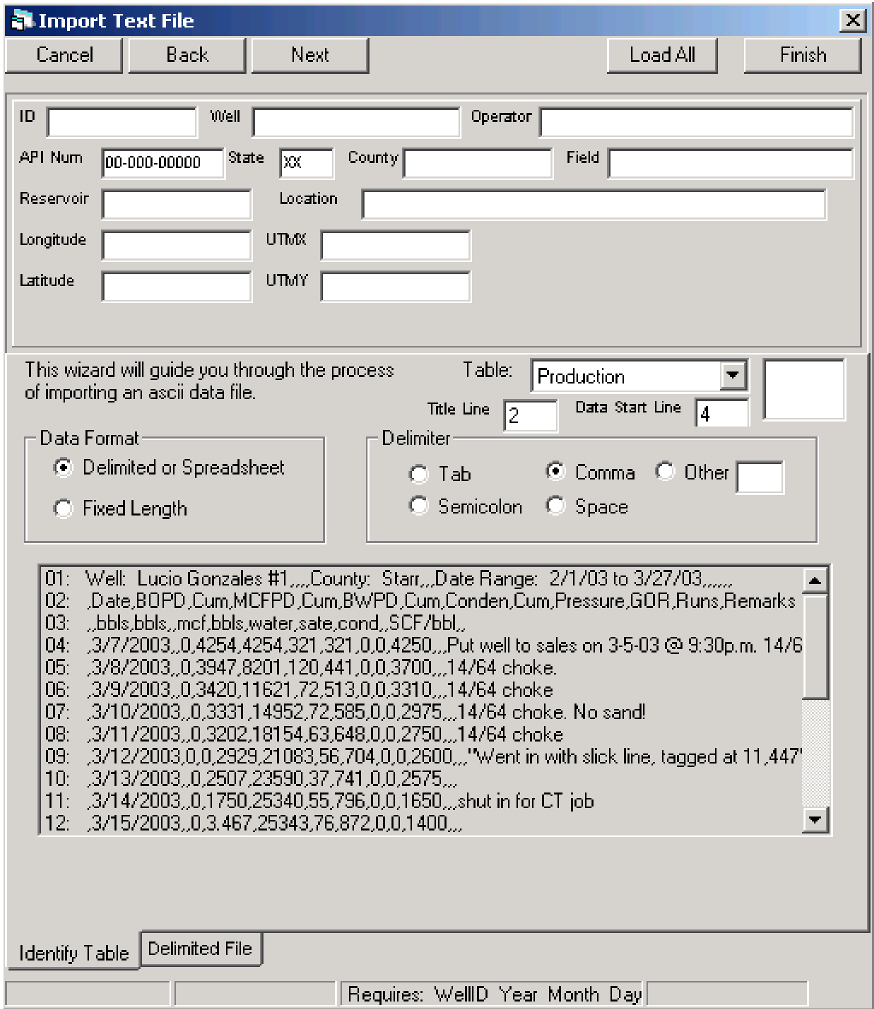

Figure 4 – Import Text File Dialog Box; Identity Table Tab

e. In the ***Title Line*** input box, indicate the line number of column header descriptions. Then, on in the ***Data Start Line*** input box, indicate the line the data begins.
f. For a delimited text file, ensure that the ***Delimited or Spreadsheet*** option under ***Data Format*** has been selected. In addition, select the appropriate delimiter for the input file.

g. The ***Import Text File*** wizard will subsequently move to the Delimited File tab window, with the data in columns, see **figure 5**.

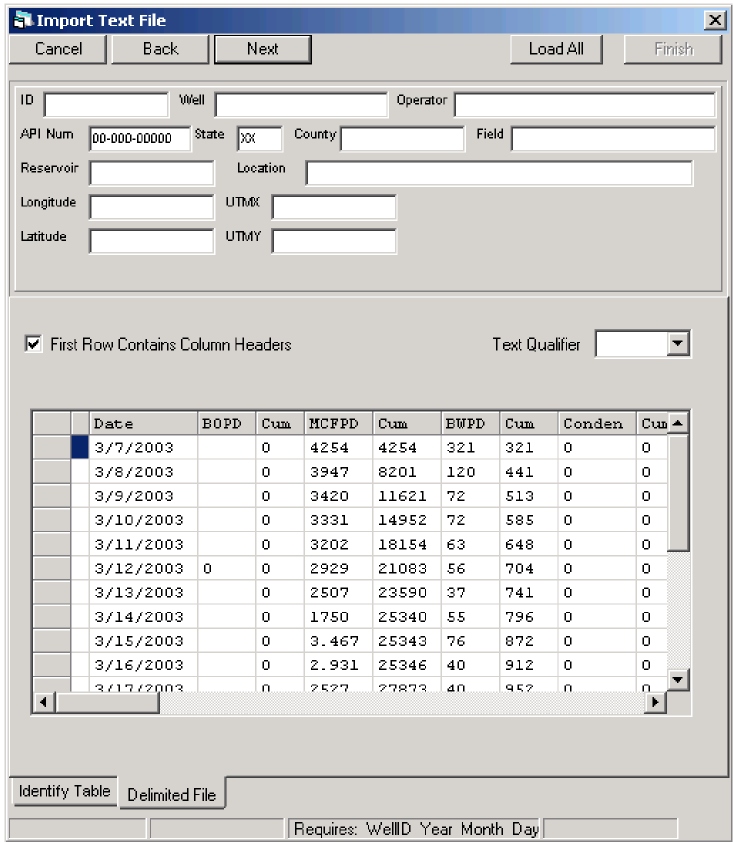

Figure 5 – Import Text File Dialog Box; Delimited File Tab

h. *METEOR* requires the input of the data to be done with the dates in Month, Day and Year columns. To convert calendar time (ie, 3/19/2003) to this format, single-click on the column header of the containing the date information. The user will be prompted to identify this as a date column. If so, select ***Yes***. The import wizard automatically generates the columns and enters the dates as Year, Month and Day in the final three columns of the worksheet. If desired, move the horizontal slider to the right to see the new data columns.

i. Select the ***Next*** button at the top of the import wizard. The ***Update Criteria*** tab will now be enabled.

j. Within the Update Criteria tab, **figure 6**, the user can indicate whether or not to ***Add New Records***, ***Update Existing Records***, and/or ***Delete Existing Records***. Depress the ***Next*** button when the criteria have been selected.

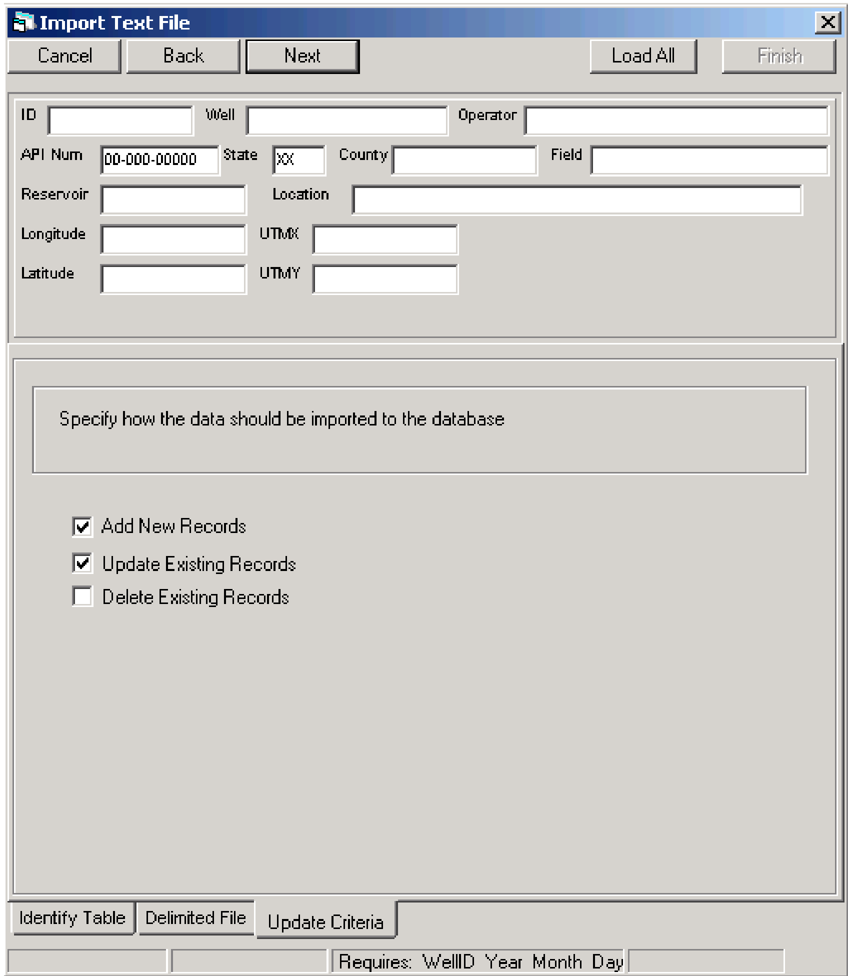

Figure 6 – Import Text File Dialog Box; Update Criteria Tab

k. The ***Assign Fields*** tab will now be enabled, **figure 7**. For importing data files, note that the bottom of the tab relates the minimum required information. Select the appropriate rate basis, ***Daily Rate***, ***Avg Daily Rate During Month***, or ***Monthly Rate*** for the dataset. NOTE: If ***Well ID*** values are not given in the input file, please enter a value in the ID input box (for a single-well input). At this time, other input values such as ***Well name***, ***Operator***, ***Field***, ***API Num.***, ***Reservoir, Location***, or well positional information may also be input (Lat/Long or UTM coordinates). For multi-well inputs, ARI recommends that these data values be input via the imported file.

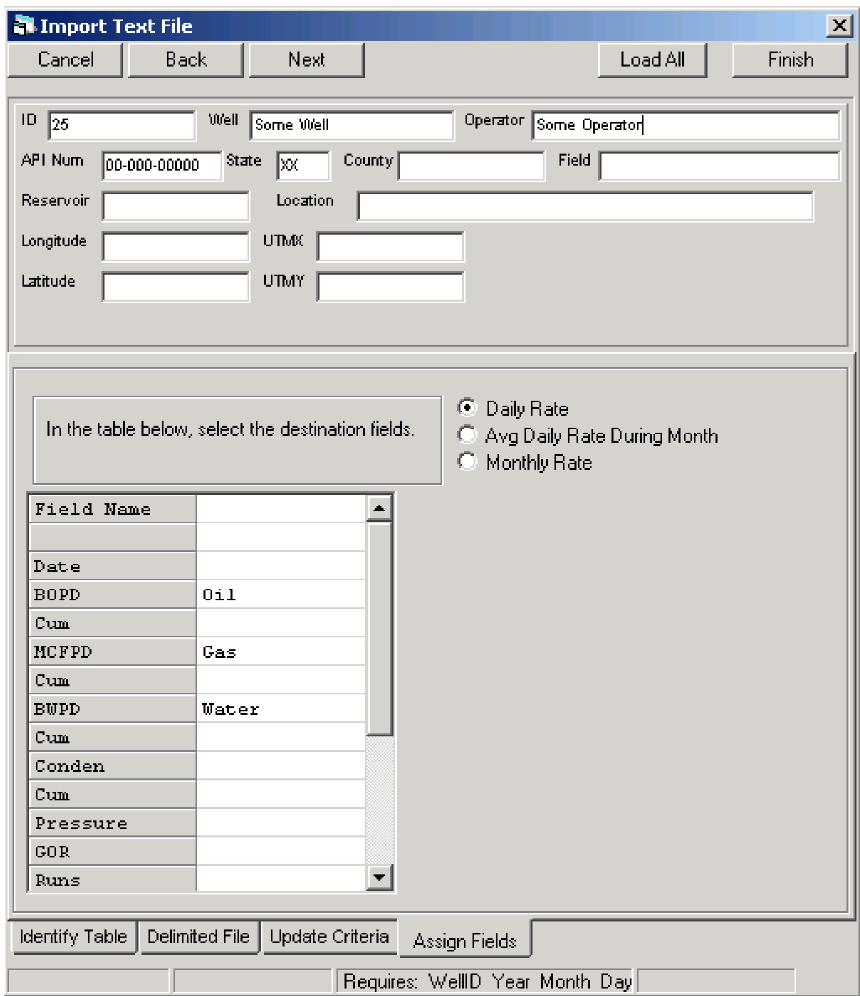

Figure 7 – Import Text File Dialog Box; Assign Fields Tab

l. Using the input worksheet in the bottom left-hand corner, select the appropriate database inputs from the drop-down menus using your mouse. Note: The header information from the .txt file has been placed on the left-hand side of the input worksheet. Directly to the right of each value, the user can access the drop-down menus for database inclusion. For example, the user's BOPD, MCFPD and BWPD will match the *METEOR* Database's Oil, Gas, and Water input criteria. See **figure 8**.

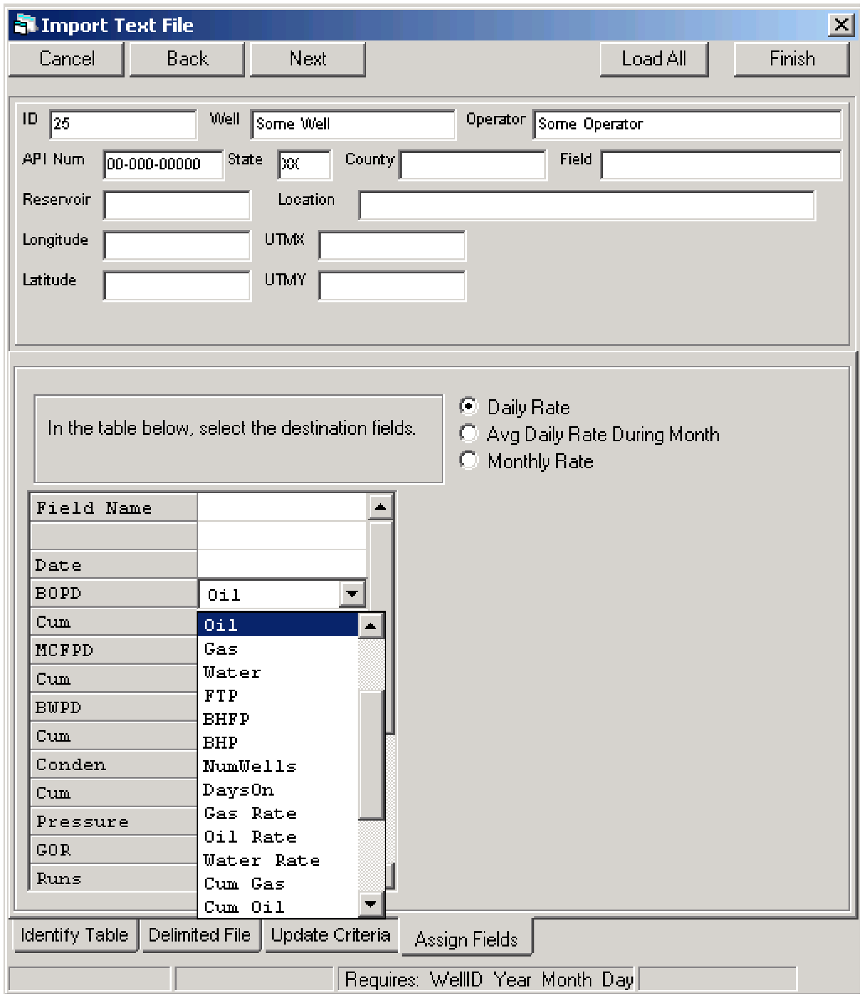

Figure 8 – Import Text File Dialog Box; Assign Fields Drop-Down Menu

m. Ensure that volume and time data (Year, Month, and Day) have been selected and depress the ***Finish*** button at the top of the window. If no well name has been selected, the user may be prompted for input.
n. The user is ready to begin the production type curve matching process.

3. Importing Microsoft Excel Files (*.xls).
   a. This version of *METEOR* was constructed using control references from Microsoft Office XP (2002). As a result, those program users employing Microsoft Excel versions prior to XP (2002) will be unable to utilize the Excel production data import protocol. If this is the case, Advanced Resources International suggests saving the Excel file as a comma delimited

text file, in either *.txt, *.csv formats, and utilizing the text importing protocol. Review Help File section I, D, 2.

b. Open or create a new *METEOR* Database (*.mdb), **figure 9**.

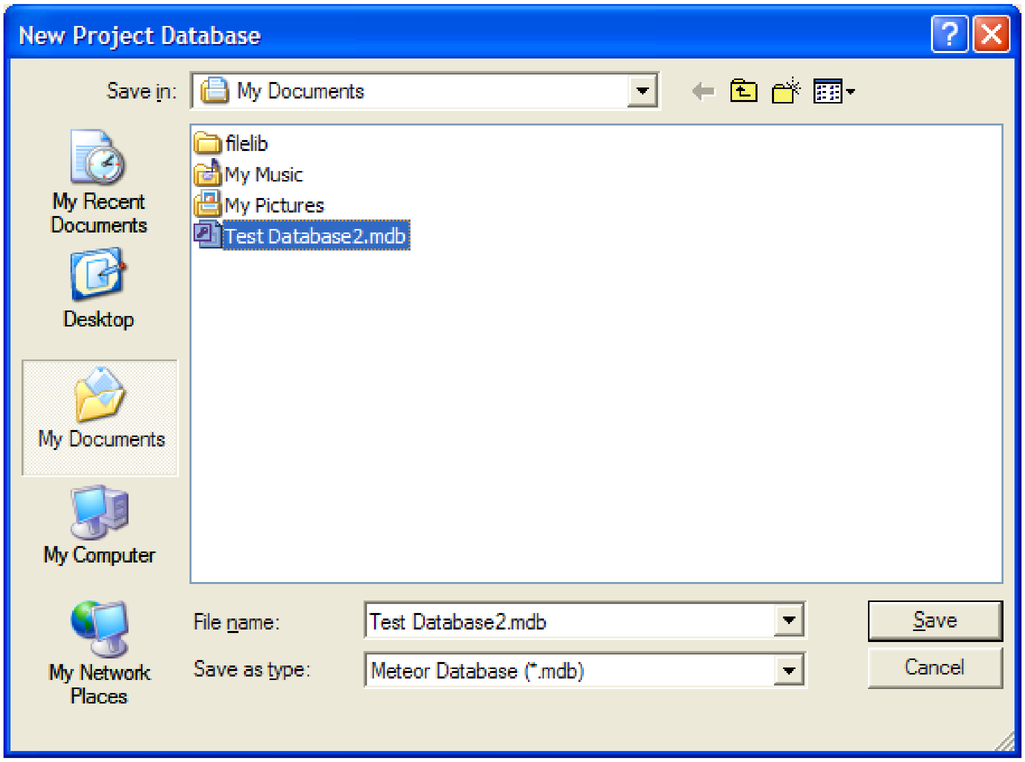

Figure 9 – New Project Database Dialog Box

c. When prompted, indicate the Excel file (*.xls) to input within the import data file dialogue box, making sure the appropriate types of file ***(*.xls)*** have been selected at the bottom of the dialogue box, **figure 10**. If necessary, navigate to the appropriate directory containing the *.xls file using the ***Look in*** drop-down box.

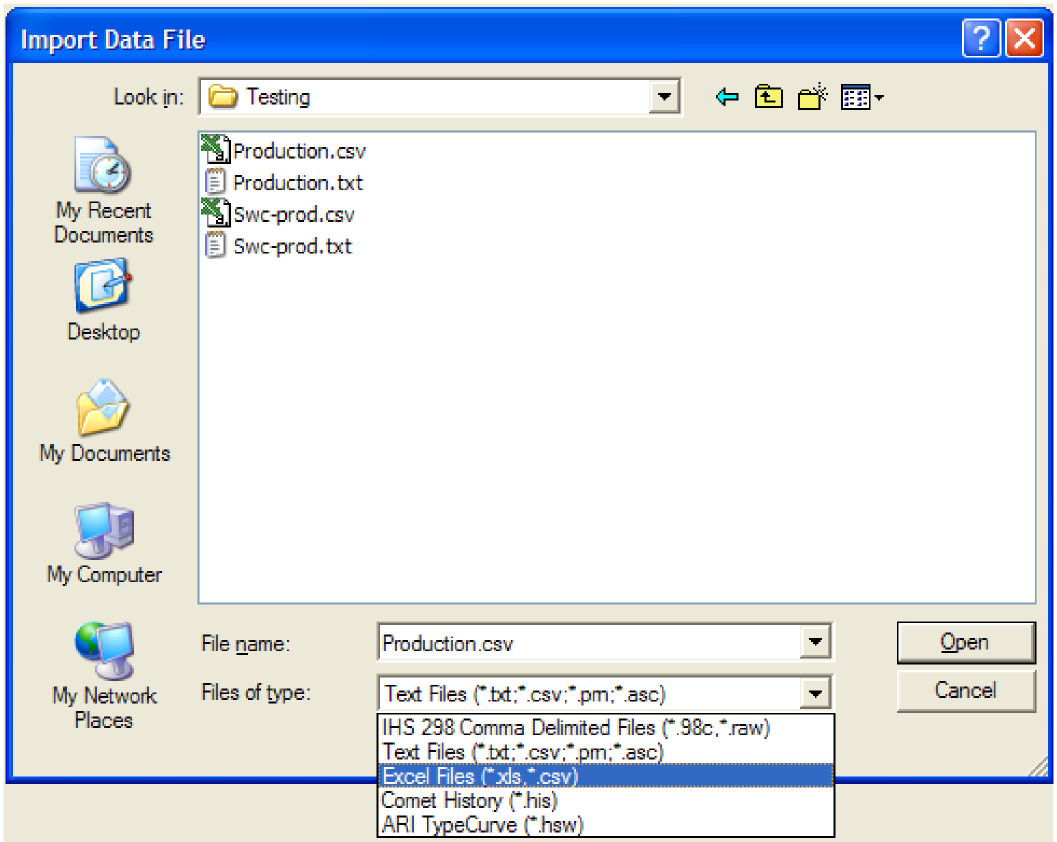

Figure 10 – Import Data File Dialog Box

d. The ***Select Import Worksheet*** will open.
e. In the upper left-hand corner, select the appropriate Excel worksheet tab containing the desired data set. The data will then appear in the bottom window, **figure 11**.

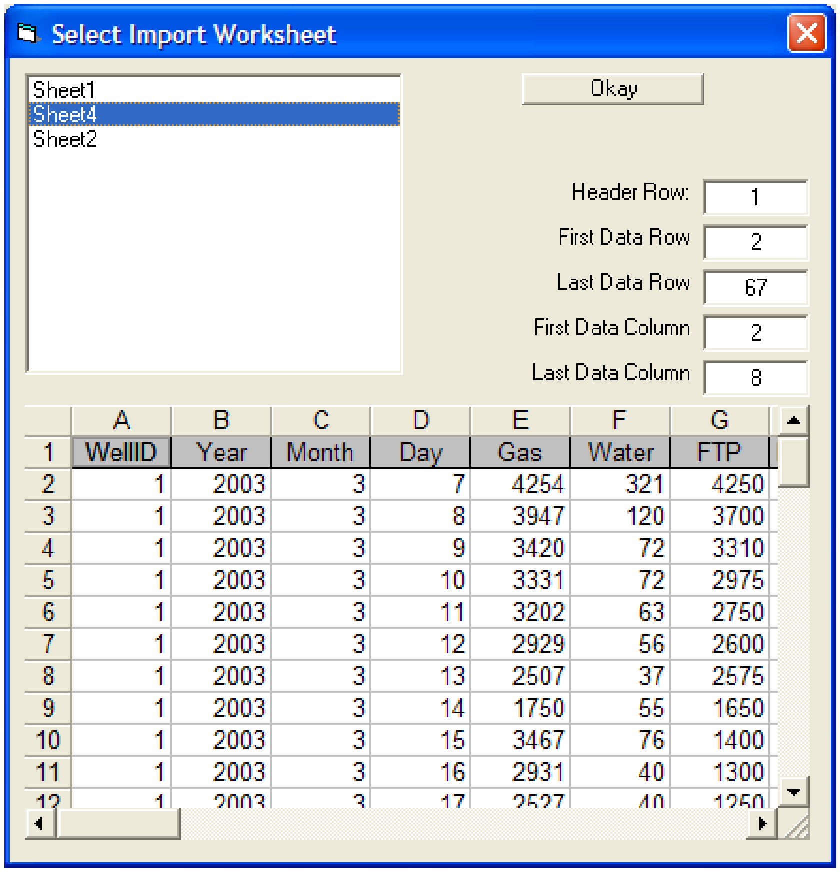

Figure 11 – Select Import Worksheet Dialog Box

f. Identify the respective positions of the ***Header Row***, ***First Data Row***, ***Last Data Row***, ***First Data Column***, and ***Last Data Column***. Any combination of numerical and alphabetical inputs for columnar input data can be used. For instance, if column number 3 contains the ***First Data Column***, a C may be used in lieu of the numeral 3. Horizontal and vertical sliders are available for scrolling the input set to confirm entries.

g. Once the row and columnar information has been entered, depress the ***OK*** button.

h. The ***Import Text File*** wizard will then appear. Select the ***Delimited File*** tab from the bottom of the window, **figure 12**. The ***Import Text File*** wizard will subsequently move to a new import window, with the import data now visible in columns.

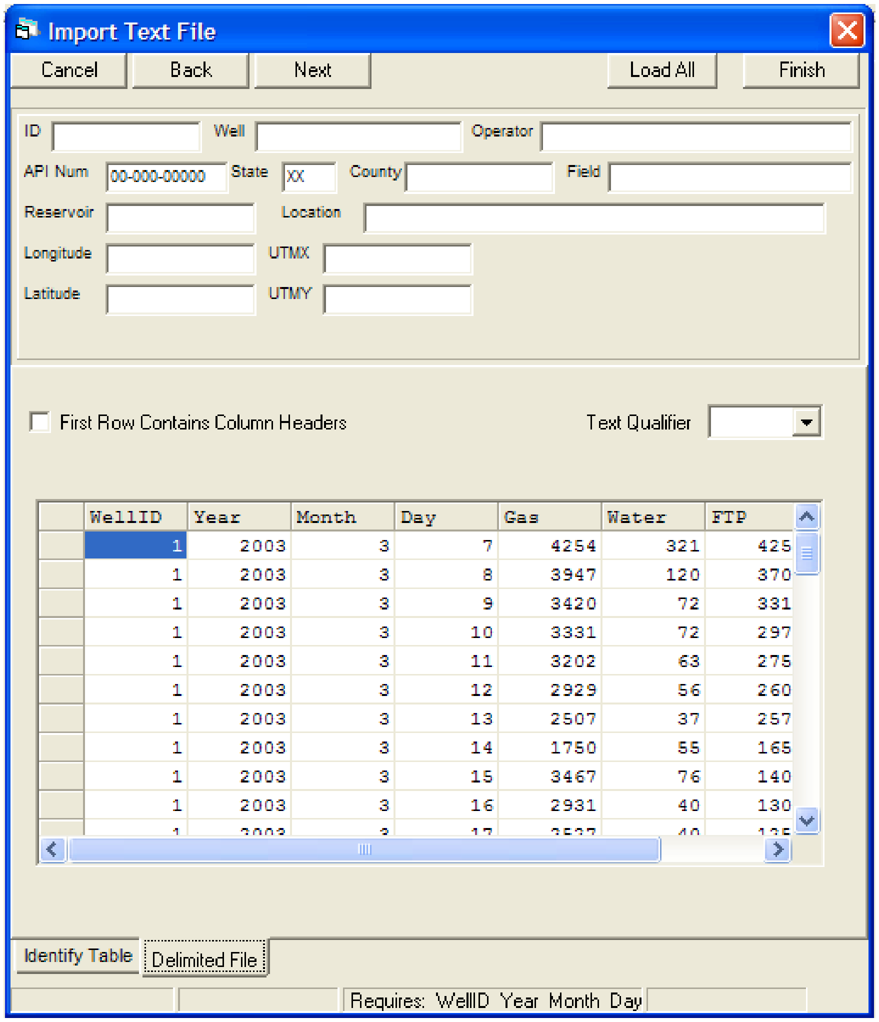

Figure 12 – Import Text File Dialog Box; Delimited File Tab

i. *METEOR* requires the input of the data to be done with the dates in Month, Day and Year columns. If it is necessary to convert calendar time (ie, 3/19/2003) to this format, single-click on the column containing the date information. The user will be prompted to identify this as a date column. If so, select ***Yes***. The import wizard automatically generates the columns and enters the dates as Year, Month and Day in the final three columns of the worksheet. If necessary, move the horizontal slider to the right to see the new data columns. If the Month, Day and Year columns are already described (as seen in **figure 12**), this step may be omitted.

j. Select the ***Next*** button at the top of the import wizard. The ***Update Criteria*** tab will now be enabled, **figure 13**.

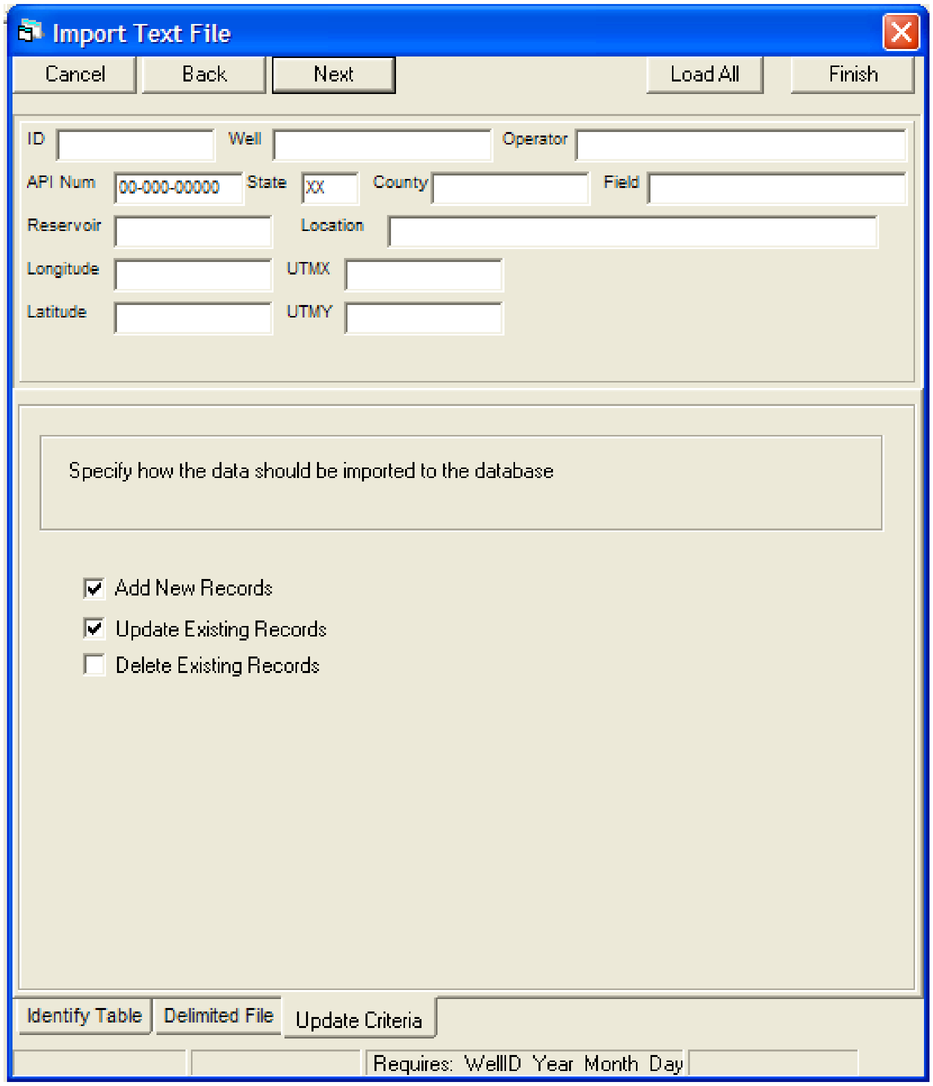

Figure 13 – Import Text File Dialog Box; Update Criteria Tab

k. Within the Update Criteria tab, the user can indicate whether or not to ***Add New Records***, ***Update Existing Records***, and/or ***Delete Existing Records*** existing records. Depress the ***Next*** button when the criteria have been selected.

l. The ***Assign Fields*** tab will now be enabled, **figure 14**. For importing data files, note that the bottom of the tab relates the minimum required information. Select the appropriate rate basis, ***Daily Rate***, ***Avg Daily Rate During Month***, or ***Monthly Rate*** for the dataset. NOTE: If ***Well ID*** values are not given in the input file, please enter a value in the ID input box (for a single-well input). At this time, other input values such as ***Well name***, ***Operator***, ***Field***, ***API Num.***, ***Reservoir, Location***, or well positional information may also be input (Lat/Long or UTM coordinates). For multi-well inputs, ARI recommends that these data values be input via the import file.

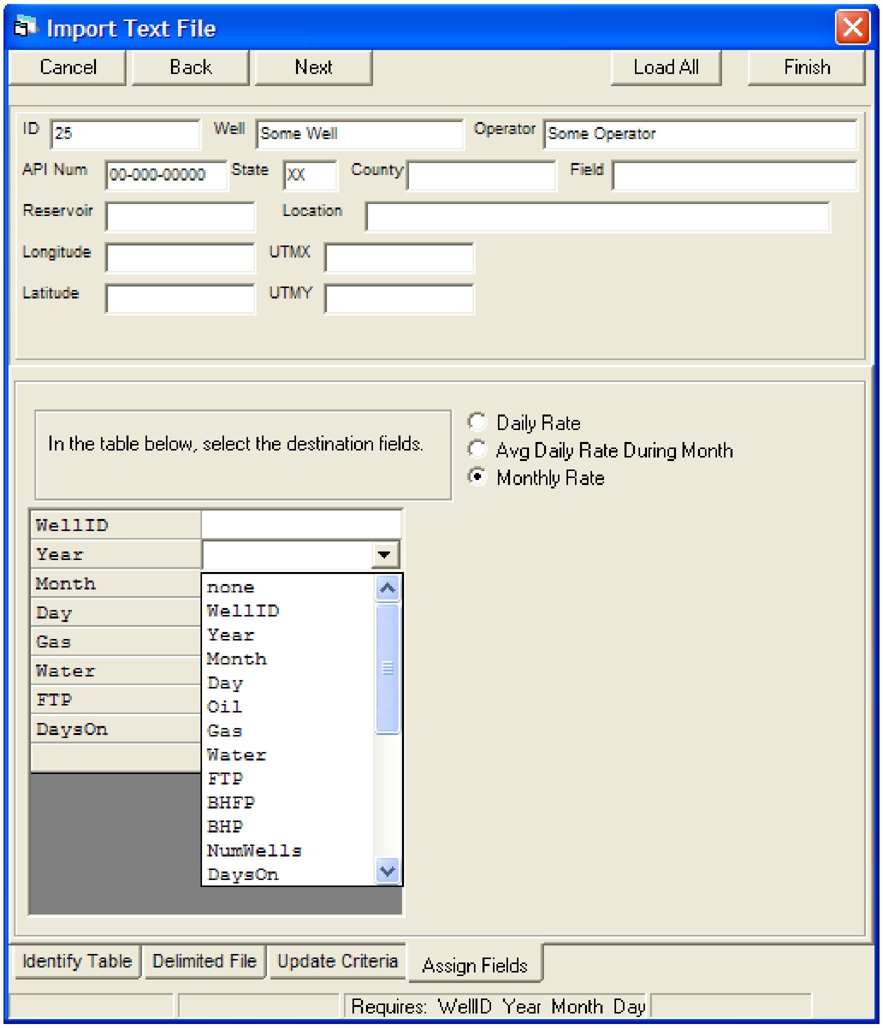

Figure 14 – Import Text File Dialog Box; Assign Fields Tab

m. Using the input worksheet in the bottom left-hand corner, select the appropriate database inputs from the drop-down menus using your mouse. Note: The header information from the .xls file has been placed on the left-hand side of the input worksheet. Directly to the right of each value, the user can access the drop-down menus for database inclusion. For example, the user's oil, gas and water rates will match the *METEOR* Database's Oil, Gas, and Water input criteria.

n. Ensure that volume and time data (Year, Month, and Day) have been selected and depress the ***Finish*** button at the top of the window. If no well name has been selected, the user may be prompted for input.

o. The user is ready to begin the production type curve matching process.

E. Viewing well data

1. A list of well names can be accessed from the drop-down menu at the left of the screen. Selecting a well name will display a production chart to the right and information for the well in fields below the well name drop-down menu. The program interface is depicted in **figure 15**.
2. The main *METEOR* window has 8 menus at the top as follows: ***File, Edit, View, Database, Analysis, Maps, Window*** and ***Help***. The functions within each are explained following.
3. The ***File*** Menu offers the following options:
    a. ***New***: Opens a new, blank project
    b. ***Open***: Opens an existing project
    c. ***Setup Printer***: To set up printer options
    d. ***Page Setup***[1]
    e. ***Print Preview***: Previews the graph in print format
    f. ***Print Chart***: Prints the chart for the active well
    g. ***Print Report***: Prints the report for the active well
    h. ***Batch Reports***: Prints reports for all wells that have been analyzed up to that point in time.
    i. ***Exit***: Exits the program
4. The ***Edit*** menu offers the following options:
    a. ***Edit Chart***: This brings up a window with options for making changes to the chart currently being worked with (see section II for details)
5. The ***View*** menu offers the following options:
    a. ***Toolbar***: Toggle on or off the toolbar
    b. ***Status Bar***: Toggle on or off the status bar at the bottom of the window
    c. ***Results Pane***: Toggle on or off the well data to the left of the chart
    d. ***Zoom/Unzoom***[1]
    e. ***Options***[1]
6. Using the ***Database*** drop-down menu you can view/manipulate the raw data using the following options:
    a. ***Import***
    b. ***Edit Well Data***
    c. ***Edit Data Tables***
7. Using the ***Analysis*** drop-down menu, the following plots can be created for each well:
    a. ***Production Plots*** (Rate vs. Calendar Time, Log Rate vs. Production Time, Rate vs. Cum Time)
    b. ***Production Type-Curve Analysis***[1]
    c. ***Variable Compressibility Decline Curve Analysis***[2]
8. The ***Maps*** drop-down menu offers the following options:
    a. ***Bubble Map*** (Cum Gas or Calc EUR)
    b. ***Background Map*** (No Background Map or Background Map from File)
    c. ***Coordinate System*** (Lat Long or UTM Coords)
    d. ***New Background Map***

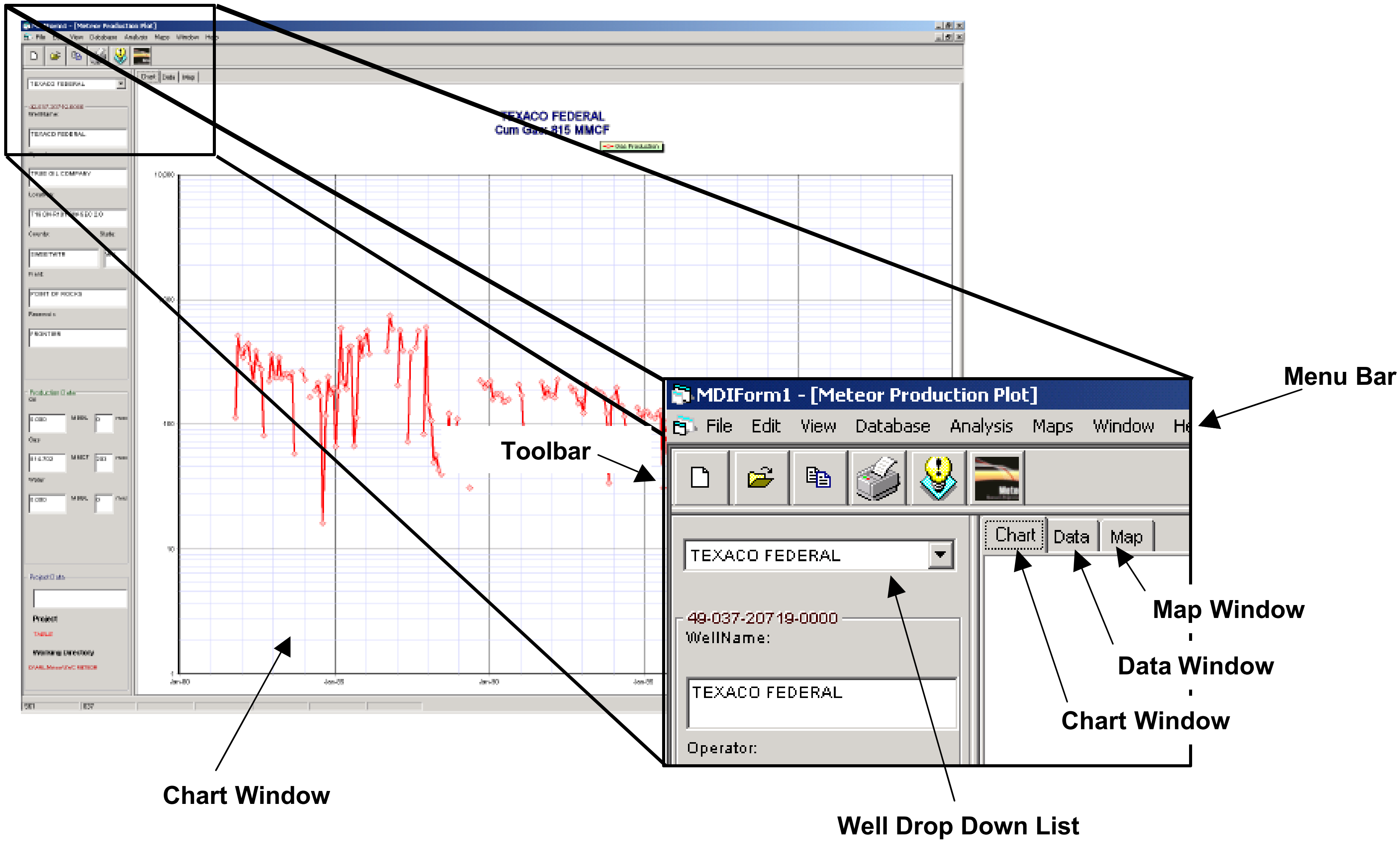

Figure 15 – *METEOR* Program Interface

9. The ***Windows*** drop-down menu allows for tiling of chart windows as well as cascading them, vertically or horizontally
10. The last menu is the ***Help*** menu. The ***METEOR*** help file can be accessed here.
11. There is also a tool bar at the top of the chart window, below the menu with the following buttons for frequently used menu features: ***New Project, Open Project, Save, Copy, Paste, Print, Help*** and the ***METEOR*** button to bring up the Hyperbolic Analysis window. Although there are no titles for the toolbar buttons, the user can "hover" the mouse cursor over a button to determine its function.

E. The Chart Window

The chart window has two additional views listed on tabs at the upper left hand of the chart. Aside from '***Chart***' there is '***Data***' which brings up the file's data in tabular format and '***Map***' which shows a locational map of all wells in the data file if positional data is available. The status bar at the bottom of the screen will display the coordinate information from the map as the cursor is moved over the screen.

There is also the option of loading in a background map from file if one is available. This background file needs to be an image file, such as a *.jpeg or *.pcx. If coordinate information is available for the corners of the image and those coordinates match the coordinate system used by the well data, the background map will align with the well locations on the ***Map*** tab. The directory location and filename for each background map must be entered into the project's *.mdb file. If more than one map is entered the arrows at the upper left of the map window can be used to toggle between the different maps.

II. Editing Charts

To edit the chart for the well currently being analyzed, bring up the Edit Chart window by selecting ***Edit Chart*** from the ***Edit*** menu. A window will appear with 8 tabs of options including ***Chart*** (including the sub-tabs ***Series***, ***Axis***, ***Titles***, ***Legend***), ***Series***, ***Export*** and ***Print***. The Edit Chart Window is depicted in **figure 16**.

A. Under the ***Chart*** tab are the following options:

1. The ***Series*** tab offers options with which the data series included on the chart can be added, removed, toggled on and off and modified.
2. The ***Axis*** tab offers options with regards to the format, numbering and appearance of the chart axes.
3. The ***Title*** tab designates the appearance of the title including font, position, style and content
4. The ***Legend*** tab turns on and off the legend and allows for formatting of fonts, symbols and the general positioning.

B. Under the ***Series*** tab are options for changing the appearance of the data series included on the chart. The color and size of the lines, points and markers can be adjusted as well as the data source.

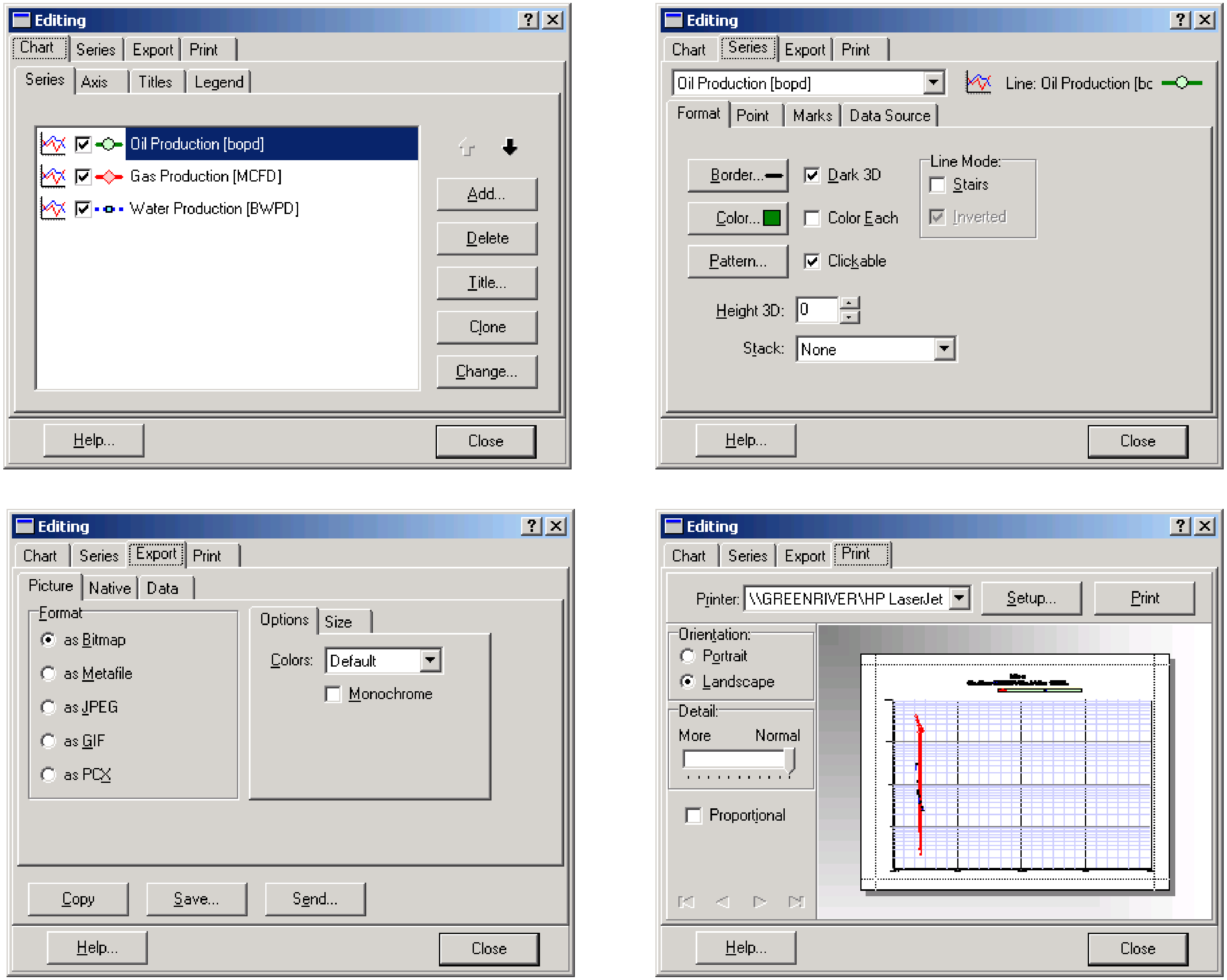

Figure 16 – Chart Editing Window

C. Under the ***Export*** tab are options for exporting the chart as the following image types: Bitmap, Metafile, JPG, GIF or PCX. The data can also be exported in the following formats: Text, XML, HTML Table and Excel.

D. The ***Print*** tab offers print set up options including orientation and level of detail as well as printer selection.

III. Single Layer Hyperbolic Type Curve Matching

A. Type Curve Matching

To type curve match a selected well, click the ***METEOR*** Button on the toolbar or under the ***Analysis*** menu choose ***Production Type-Curve Analysis***. This will bring up the Single Layer Type Hyperbolic Curves window. This window is depicted in **figure 17**. The data points can be matched to the type curve by clicking the appropriate arrow on the ***Shift Points*** four-way arrow button in the lower right corner of the window. This button shifts the data points up, down, left and right to enable the user to match the data to the appropriate type curve. Immediately to the left of the button is a ***Movement Sensitivity*** slider bar, which allows fine to coarse movements on a scale of one (fine) to ten (coarse). The data may also be shifted by selecting the Move button from the toolbar and clicking and dragging the data with the mouse. To aid in matching use the features in the lower left corner of the window, **figure 18**. Use the ***Xe/Xf*** drop-down menu to select the appropriate drainage stem the data is being matched to. Also, the hyperbolic exponent may be adjusted to change the shape of the ARPS decline curves to better fit the data. The data ***Smoothing*** option calculates a moving average of the data points on a 3-point to 11-point basis.

There are nine main toolbar features available for the user as well as two sub-toolbar features for use in the movement of the production data. The ***Save*** button acts much the same as the ***Update*** button, allowing the user to save the data match to the database file. For the movement of the data, the user can select the ***Move*** button, which allows the user to click-and-drag the data using the mouse.

Used in conjunction with the ***Move*** button, the user can alter the sensitivity of the data movements (using the mouse) by changing the setting on the ***Movement Sensitivity*** slider bcated below the toolbar. A setting of one indicates fine movements while a setting of nine indicates the coarsest data movements, see **figure 18**. The ***Update/Show Match Point*** sub-feature will plot the current match point on the type curve match. If the user then reselects this feature following additional movement of the data, the new match point will be depicted with respect to the previous match point.

The user is also supplied with ***Zoom*** and ***Unzoom*** controls for refinement of the type curve match. Selecting the ***Zoom*** toolbar button and clicking and dragging a rectangle over the area of interest enlarges the range for user review. Selecting ***Unzoom*** restores the match to the original perspective. Note: if the user zooms in more than once, the Unzoom feature will not restore the plot to the original perspective, but to the previous

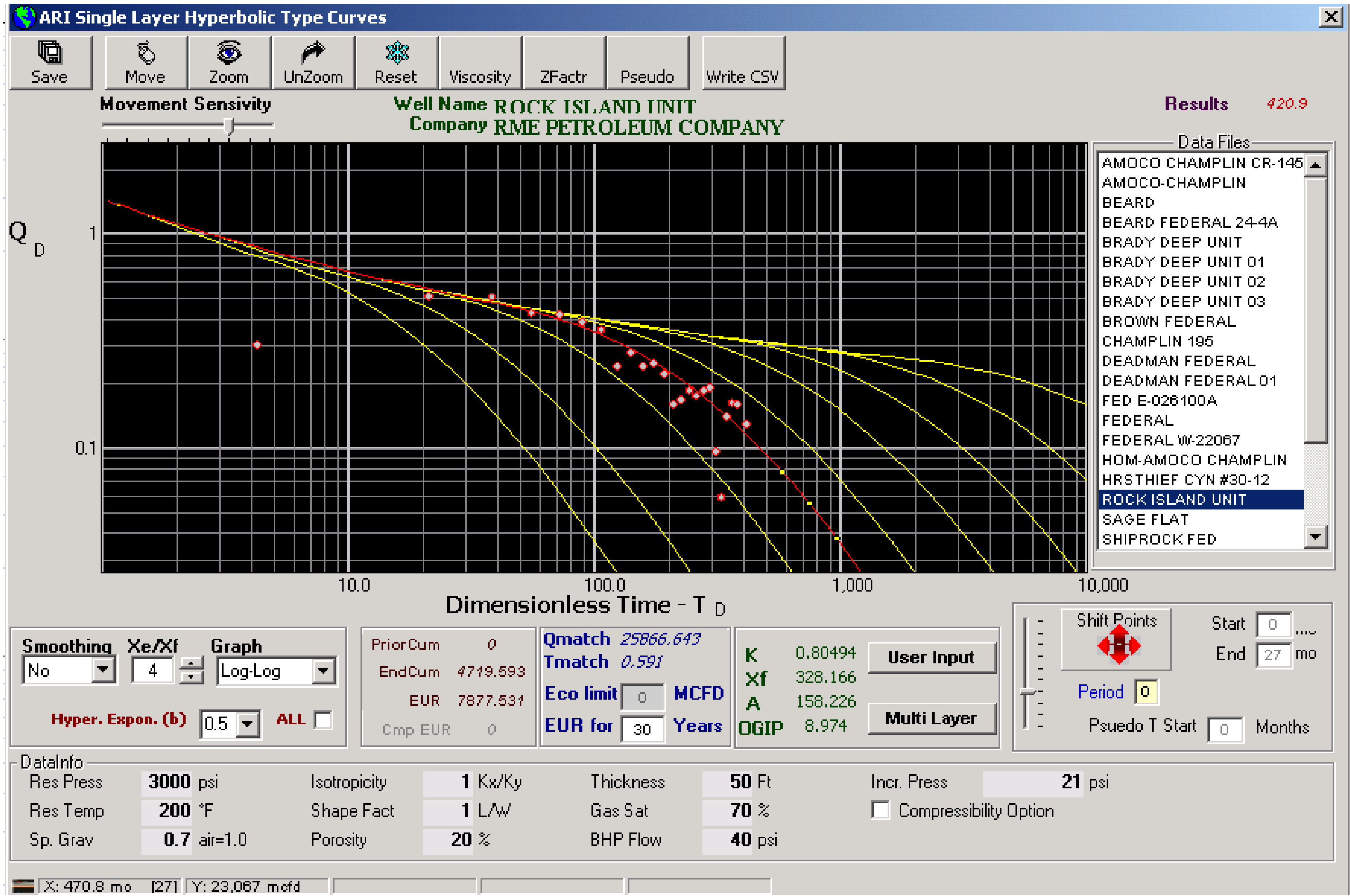

Figure 17 – Type Curve Matching Interface Window

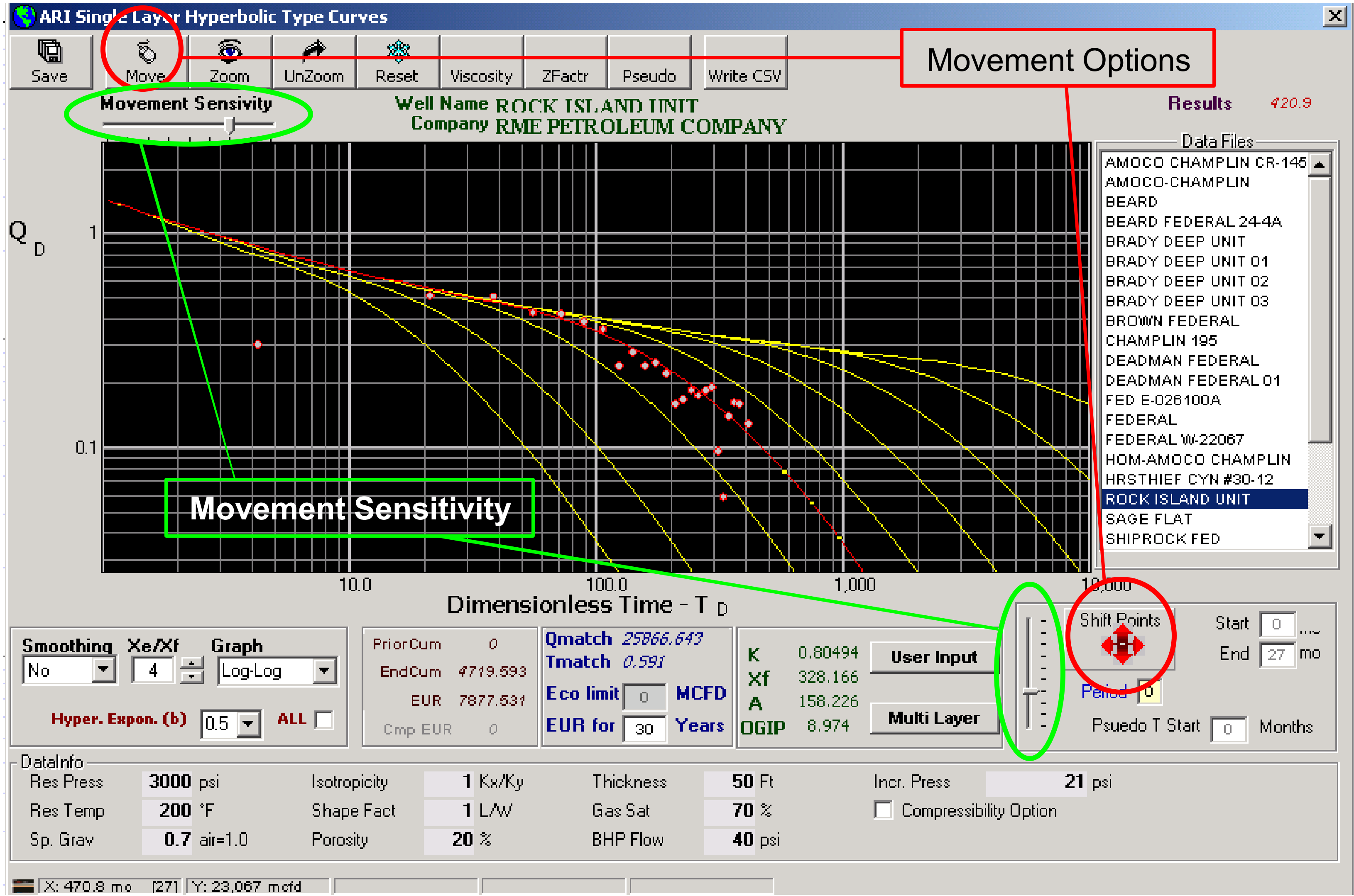

Figure 18 – Data Movement Options within the Type Curve Interface Window

perspective. To fully unzoom in this case, select the ***Reset toolbar button***, which the user can also invoke to refresh the plot.

The remaining toolbar features – ***Viscosity, ZFactr,*** and ***Pseudo*** – show the respective gas viscosity, z-factor and pseudopressure (real gas potential) for the gas described in the user input dialogue. When selected, a graphical representation of the property on the y-axis is plotted against the range of zero to reservoir pressure.

Click the ***User Input*** button to bring up reservoir and well data inputs. These can also be accessed by a right mouse click on the data into fields at the bottom of the window. After entering new reservoir and well data inputs click on the ***Update*** button. After updating, note that the calculated results are also updated. Therefore, it is important to enter representative values for reservoir and well inputs.

B. Restarts

METEOR has the capability to handle changes in operating conditions, well workovers and re-stimulations through the use of the ***Restart*** option. To utilize the restart option, the user must first type in a "1" in the ***Period*** text box. The ***Period*** text box is located to the right of the Shift Points button. If there is a second restart, a "2" is entered, and so on. Once a value is input in the Period text box, the user is prompted to save the original match. Restart controls are show in **figure 19**.

The user then must input the month, in elapsed production time that the restart will occur in the ***Start*** text box. The ***End*** text box will then contain the final production month that will be considered for type curve matching of the particular restart. Conversely, the user may wish to use the ***slider bar*** located below the ***Shift Points*** button and the ***Start*** and ***End*** text boxes to select the beginning and end of the restart period. Note that the data disappears from the type curve plot as the slider is moved from the left to the right.

After the appropriate restart period has been selected, a number will appear to the right of the ***Period*** text box. This value must be input into the ***Pseudo TStart*** text box to initialize the restart period for matching. As the user enters the value, the type curve restart will re-initialize, allowing the user to assess the impact of the restart period. Also, *METEOR* will automatically decrement the value in the ***Pseudo TStart*** text box by a value of one.

IV. Multi-layer Hyperbolic Type Curve Matching

Click the ***Multi Layer*** button to open the ***Multi Layer*** matching window, **figure 20**. Enter the appropriate information for each layer, including gas saturation, thickness, porosity and decline exponent. Once the numbers are entered, click ***Plot*** to see the curves. Complete the match by adjusting permeability, fracture half-length and drainage area until the summation curve matches with the match result curve. Use the ***Grid*** check box to toggle on and off the grid lines. Once the match is complete click the ***Update***

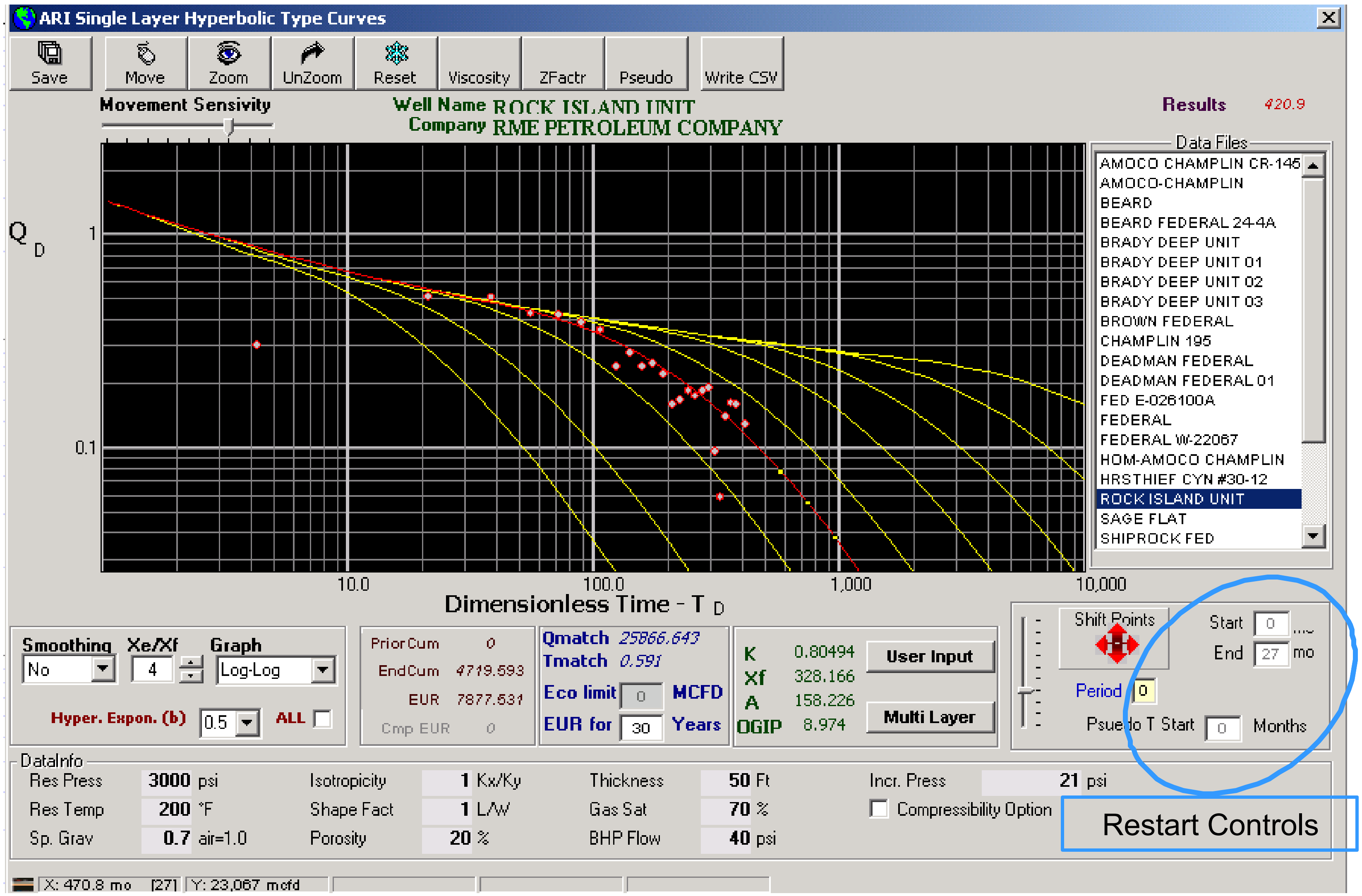

Figure 19 – Restart Controls within the Type Curve Interface Window

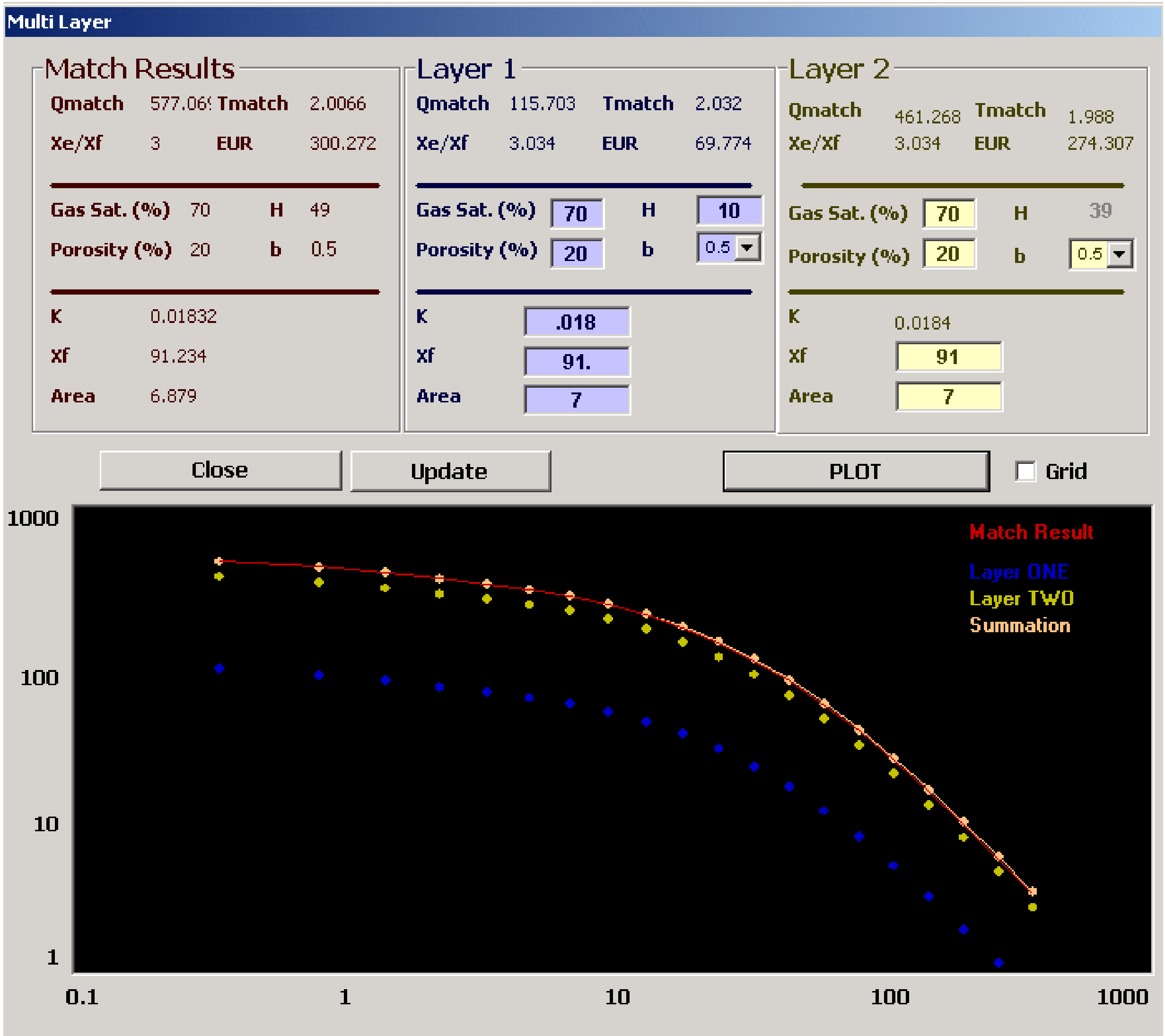

Figure 20 – Multi-layer Hyperbolic Type Curve Matching Window

button to save the match results for that well. Both this window and the Single Layer Type Curves window can now be closed and analysis begun on a new well.

V. Variable Compressibility Type Curve Matching

In addition to the single and multi-layer hyperbolic type curve matching options, the user also has the capability to estimate the impact of pressure depletion on PVT properties such as gas compressibility and gas viscosity in low permeability gas reservoirs. This effect generally manifests itself following the departure from the infinite acting portion of the type cure (or when a boundary is encountered). From a practical standpoint, this behavior deviates from the decline stem (selected match Xe/Xf) and often crosses over others to the right. The Variable Compressibility Type Curve Matching option is shown in **figure 21**.

To activate this feature, the user must select the ***Compressibility Option*** check box. A heavy green line then appears, allowing the user to refine the match. To do so, the user must typically decrease the selected Xe/Xf match point until the variable compressibility line passes through the production data.

VI. Disclaimer

This software was prepared as an account of work sponsored agencies of the United States Government and the State of New York. Neither the United States Government, the State of New York nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of the software.

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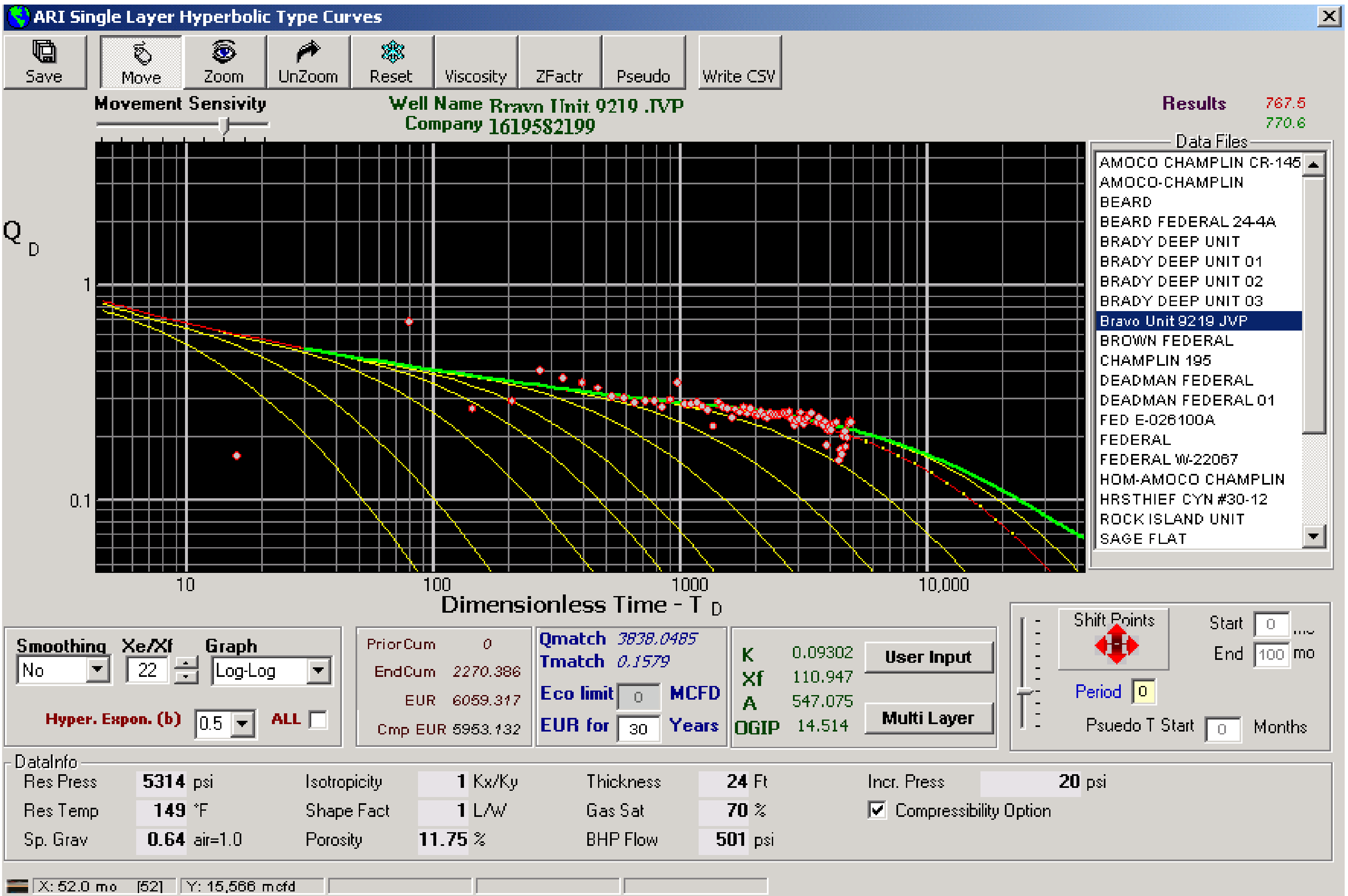

Figure 21 – Variable Compressibility Type Curve Matching Option

Appendix 2

METEOR Software Installation CD

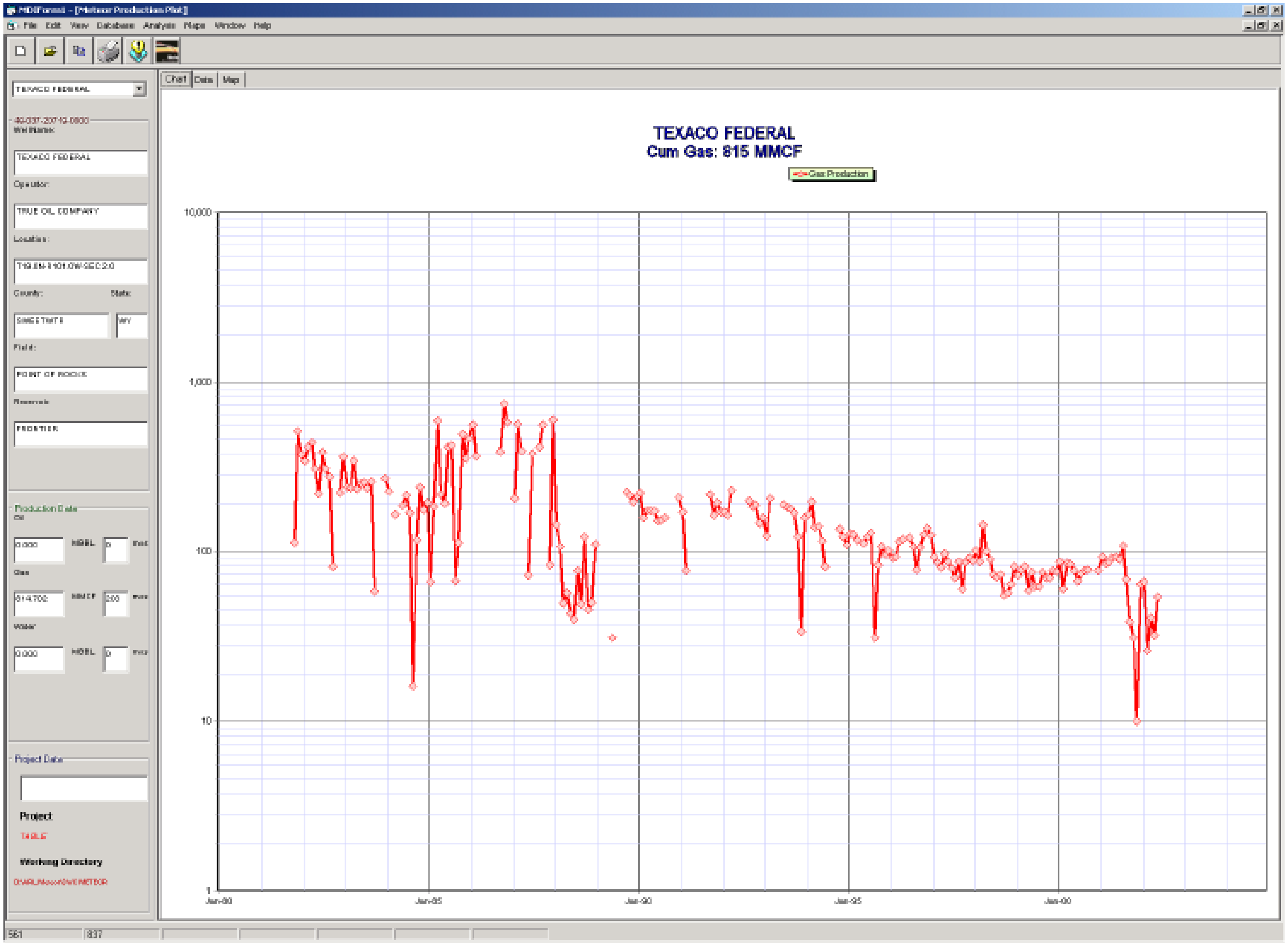

Figure 1 – *METEOR* Program Interface

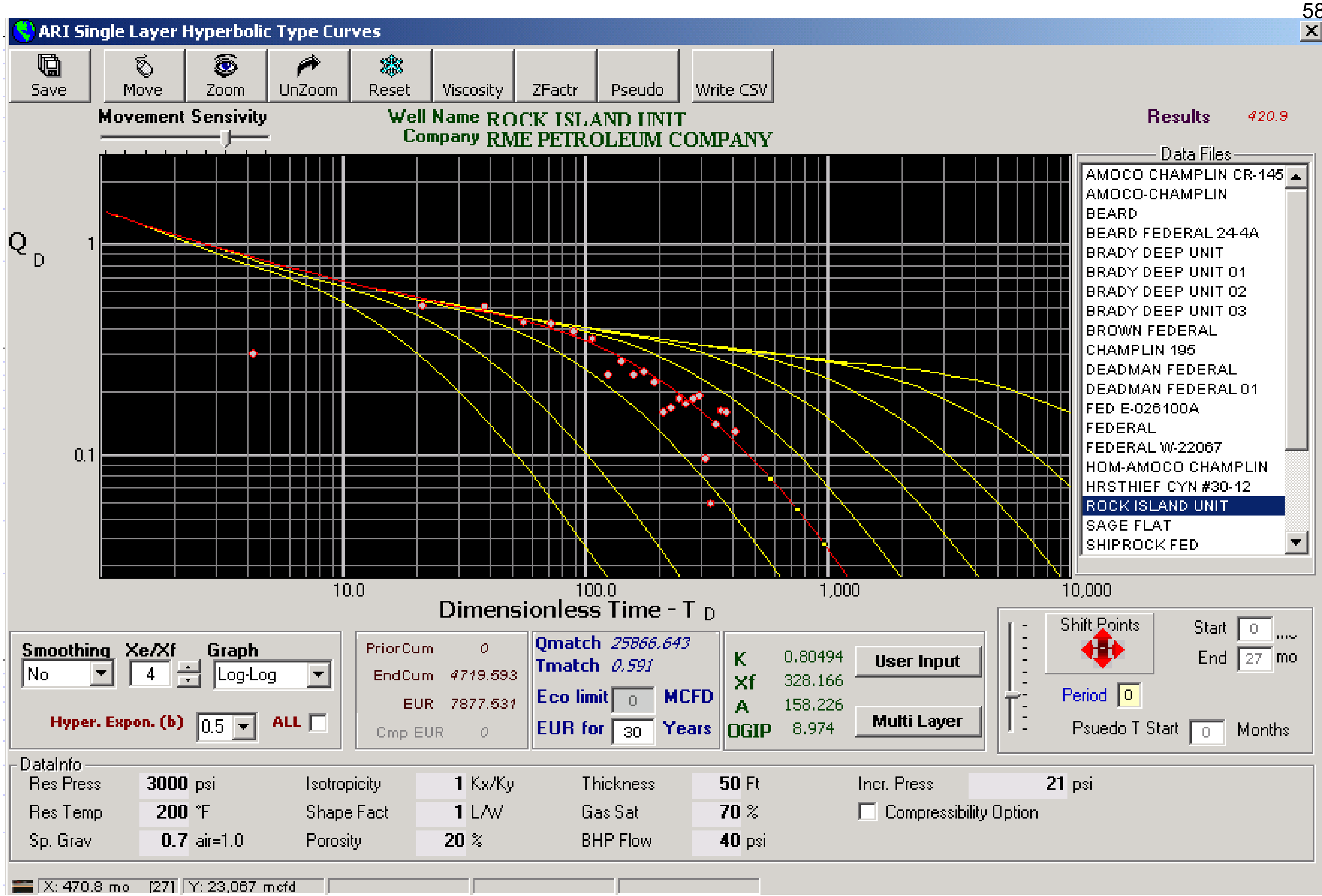

Figure 2 – *METEOR* Single-Layer Hyperbolic Type Curve Matching Interface

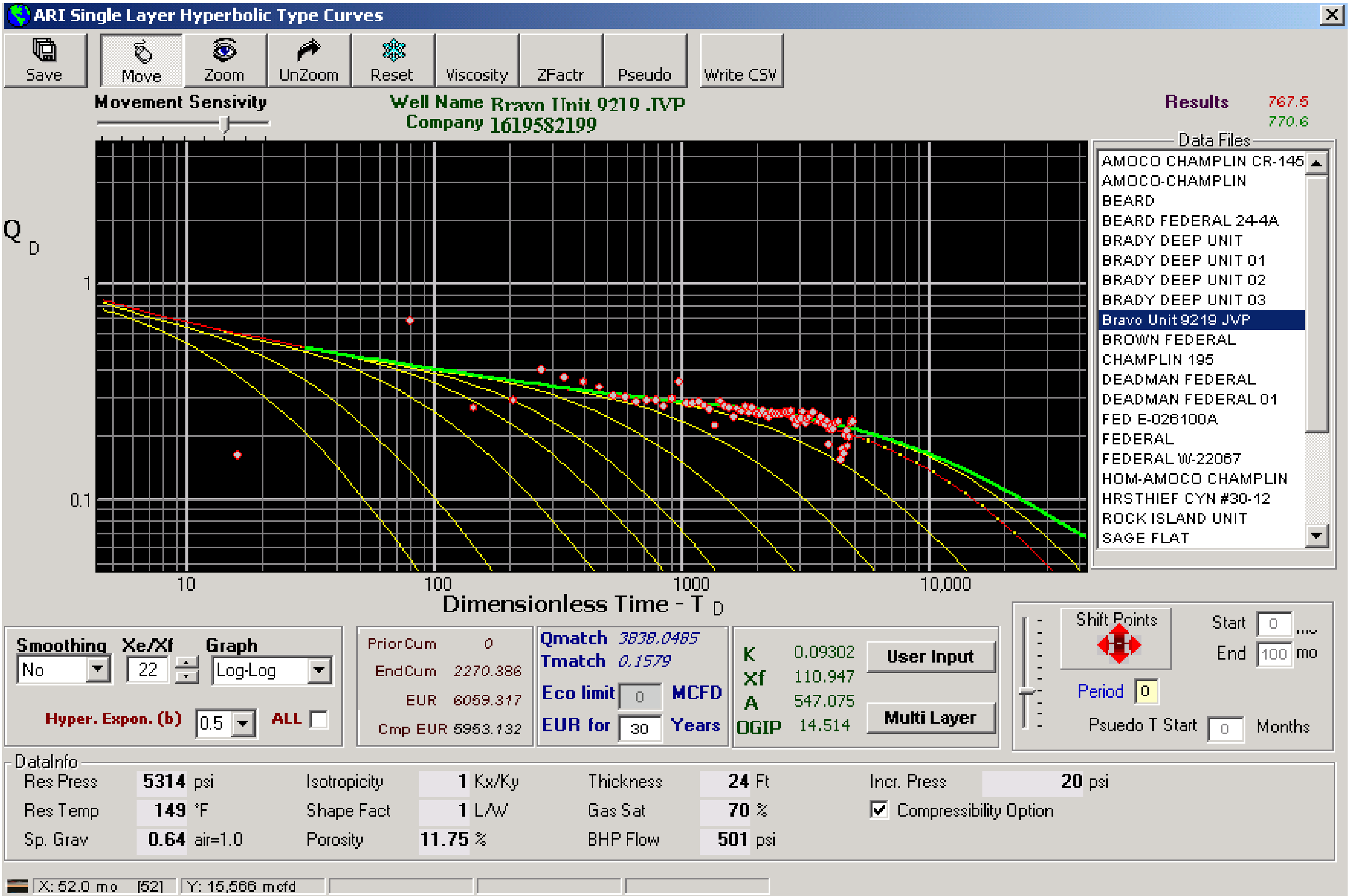

Figure 3 – Variable Compressibility Type Curve Matching Option

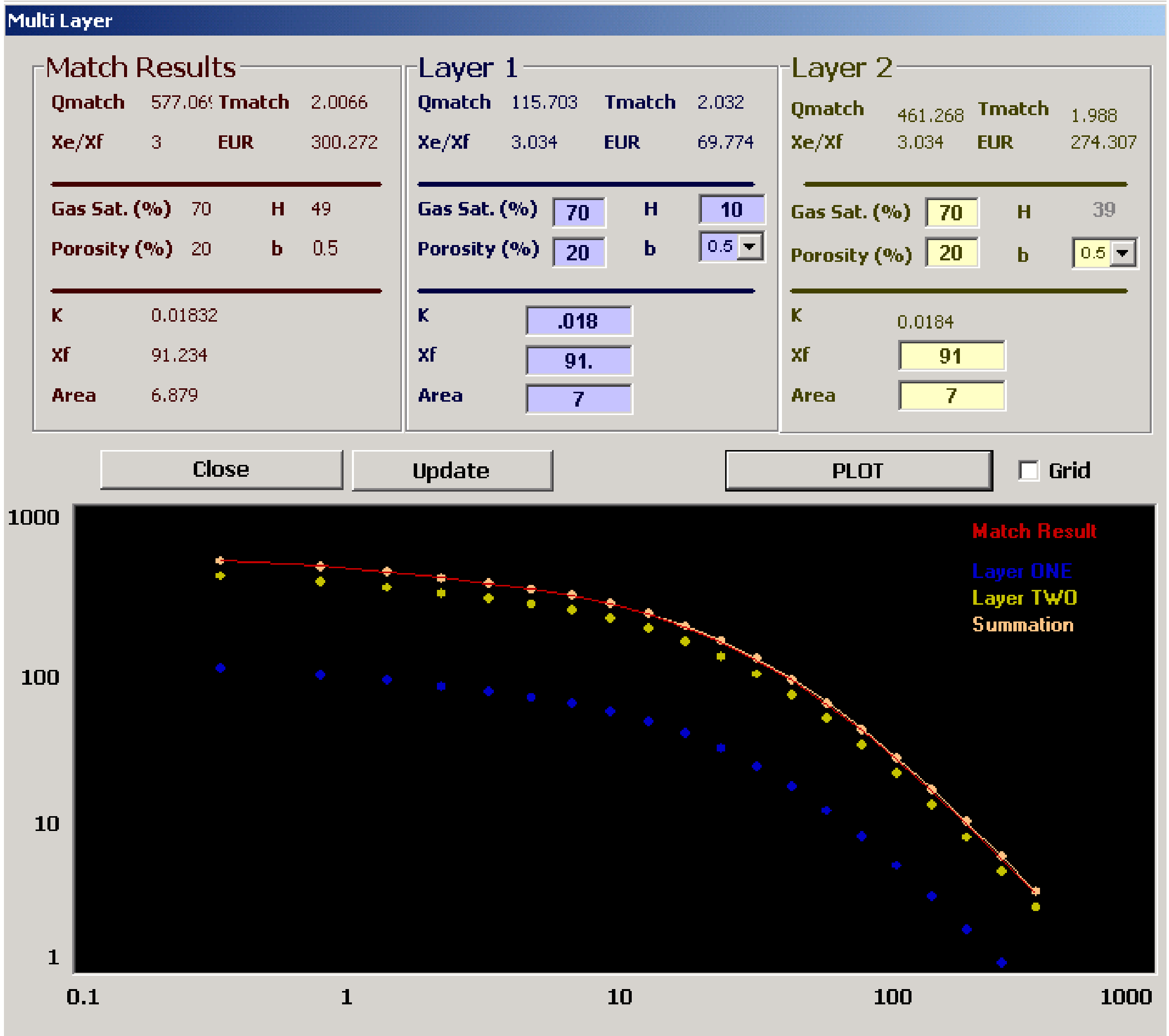

Figure 4 – *METEOR* Multi-Layer Hyperbolic Type Curve Matching Interface

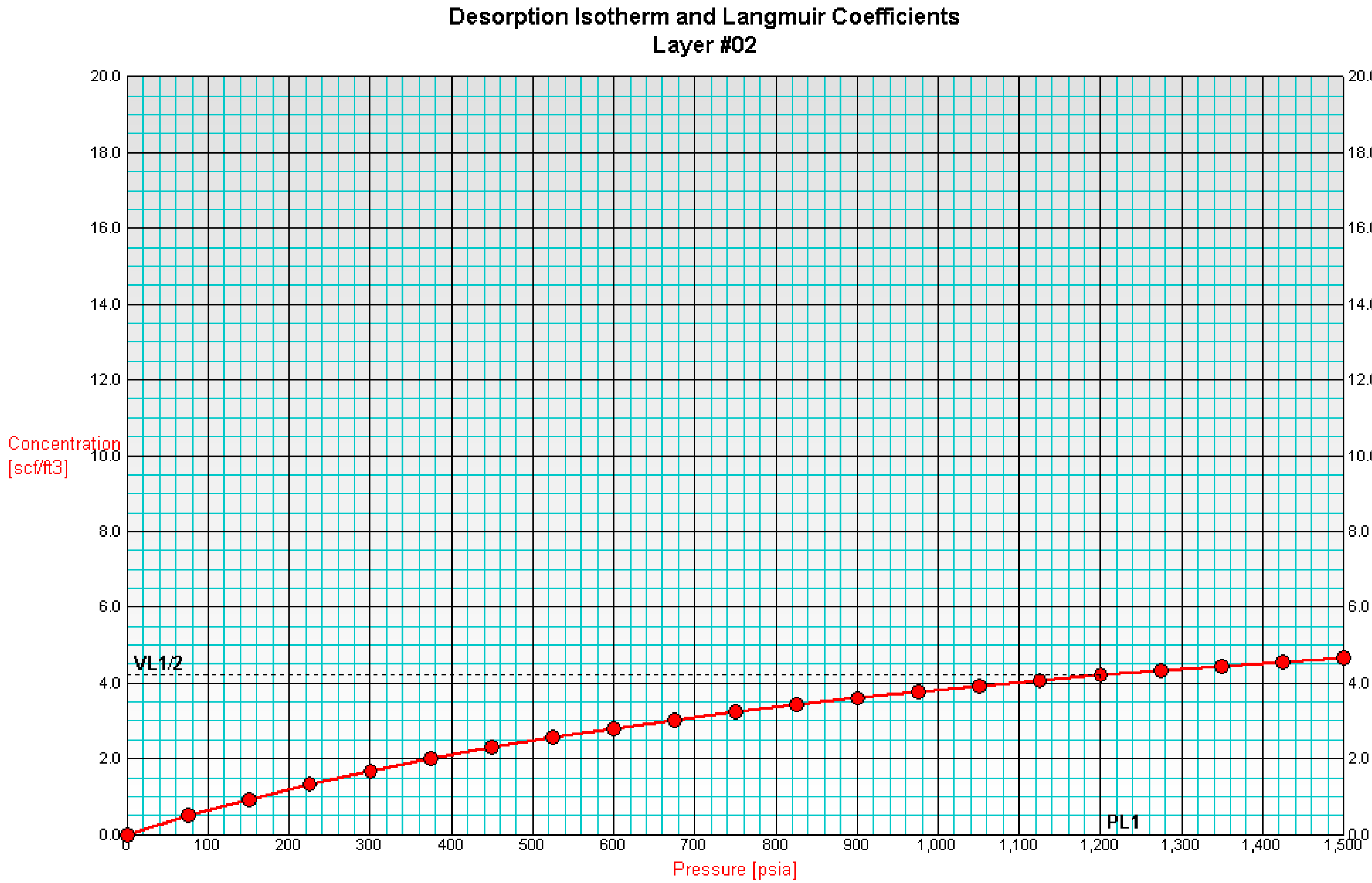

Figure 5 – Devonian Shale Adsorption/Desorption Isotherm

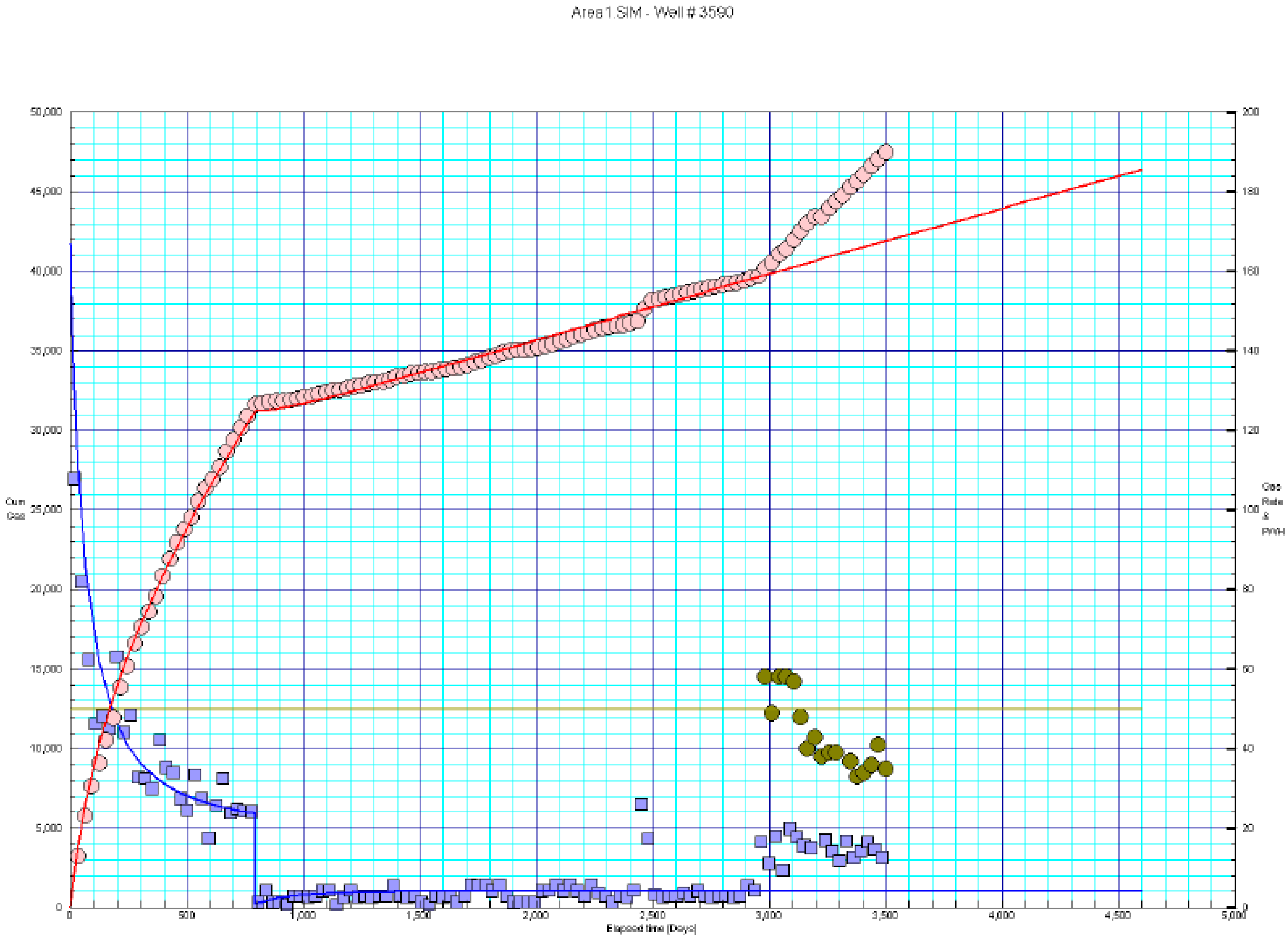

Figure 6 – History Match for Area 1

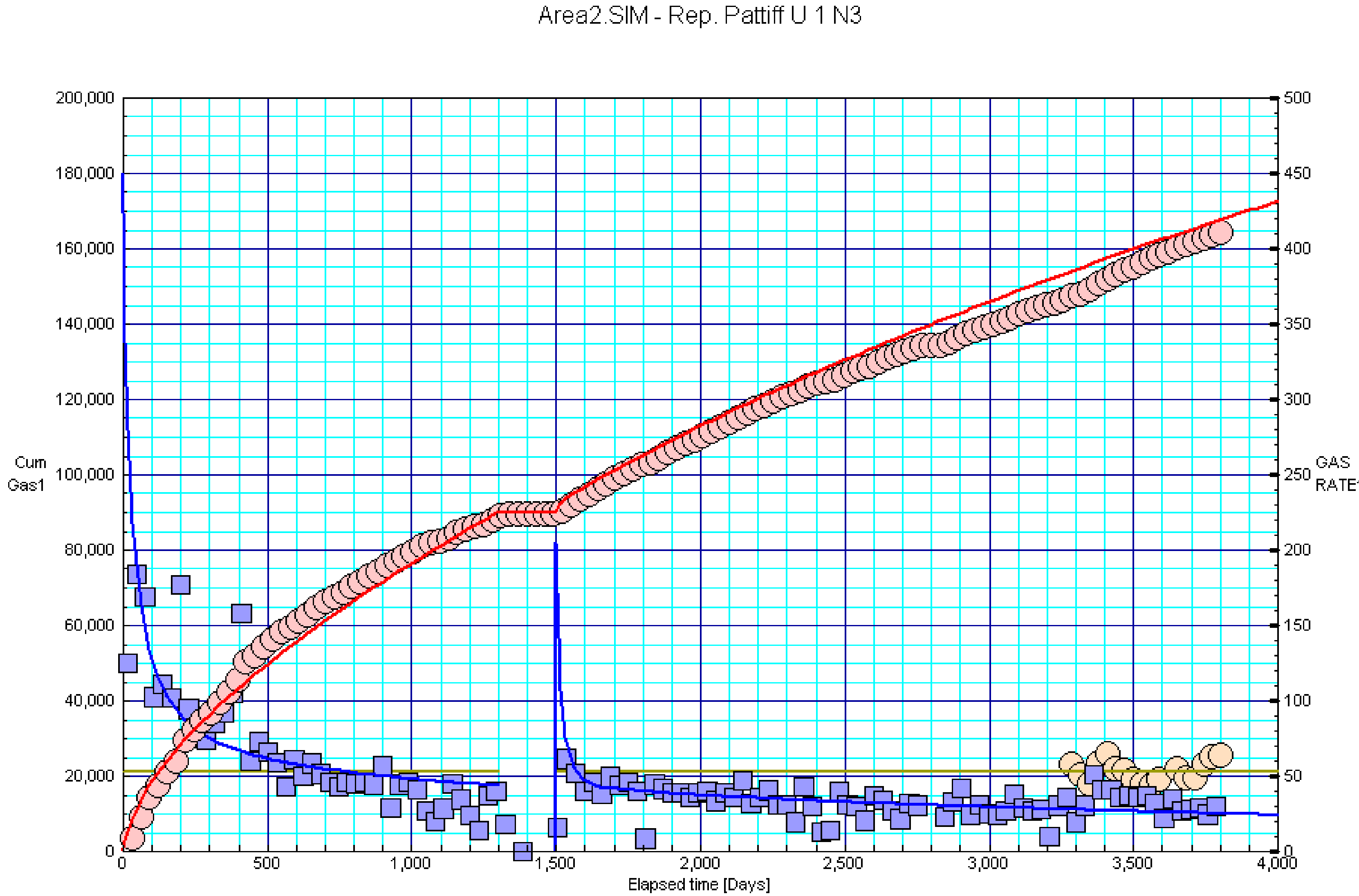

Figure 7 – History Match for Area 2

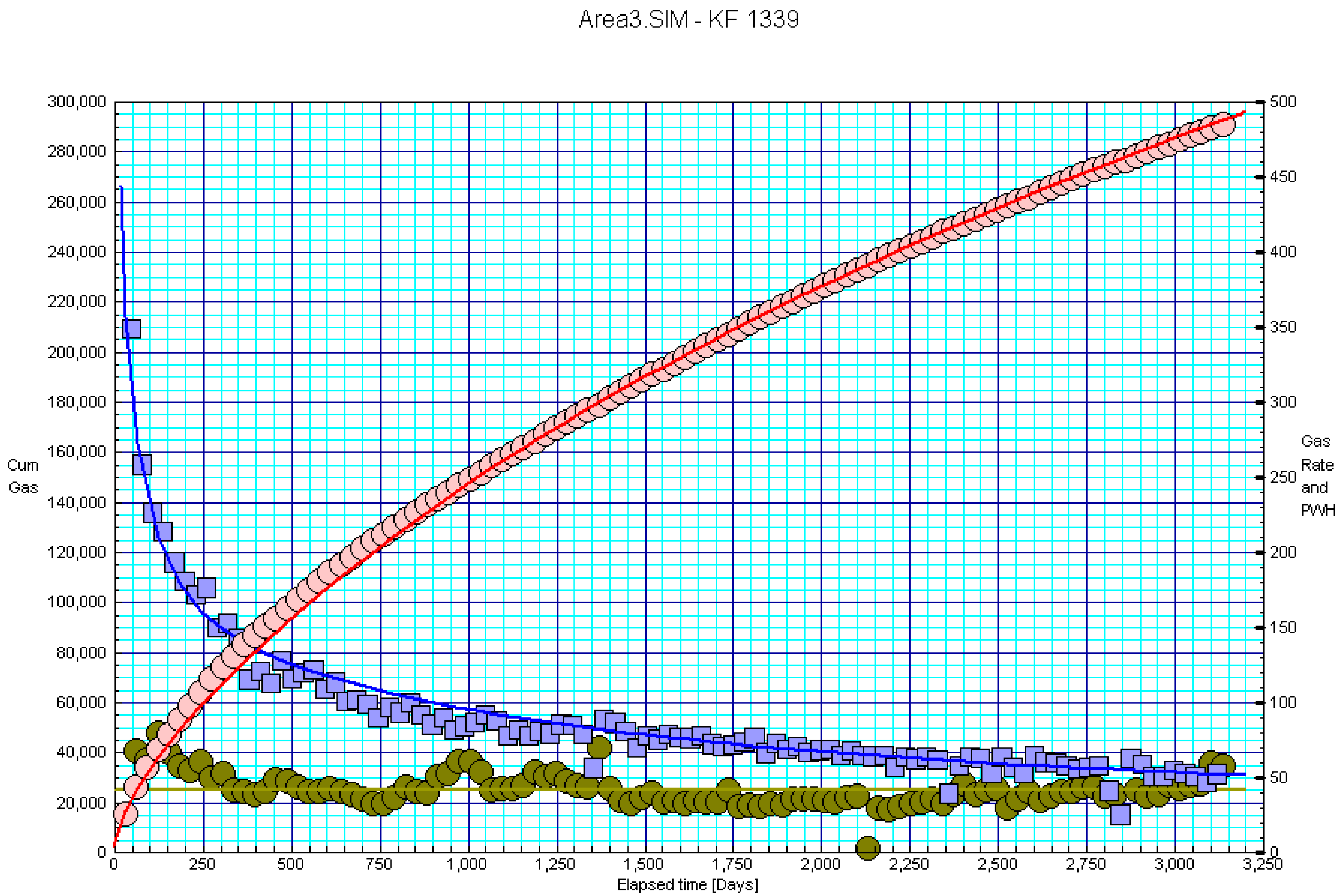

Figure 8 – History Match for Area 3

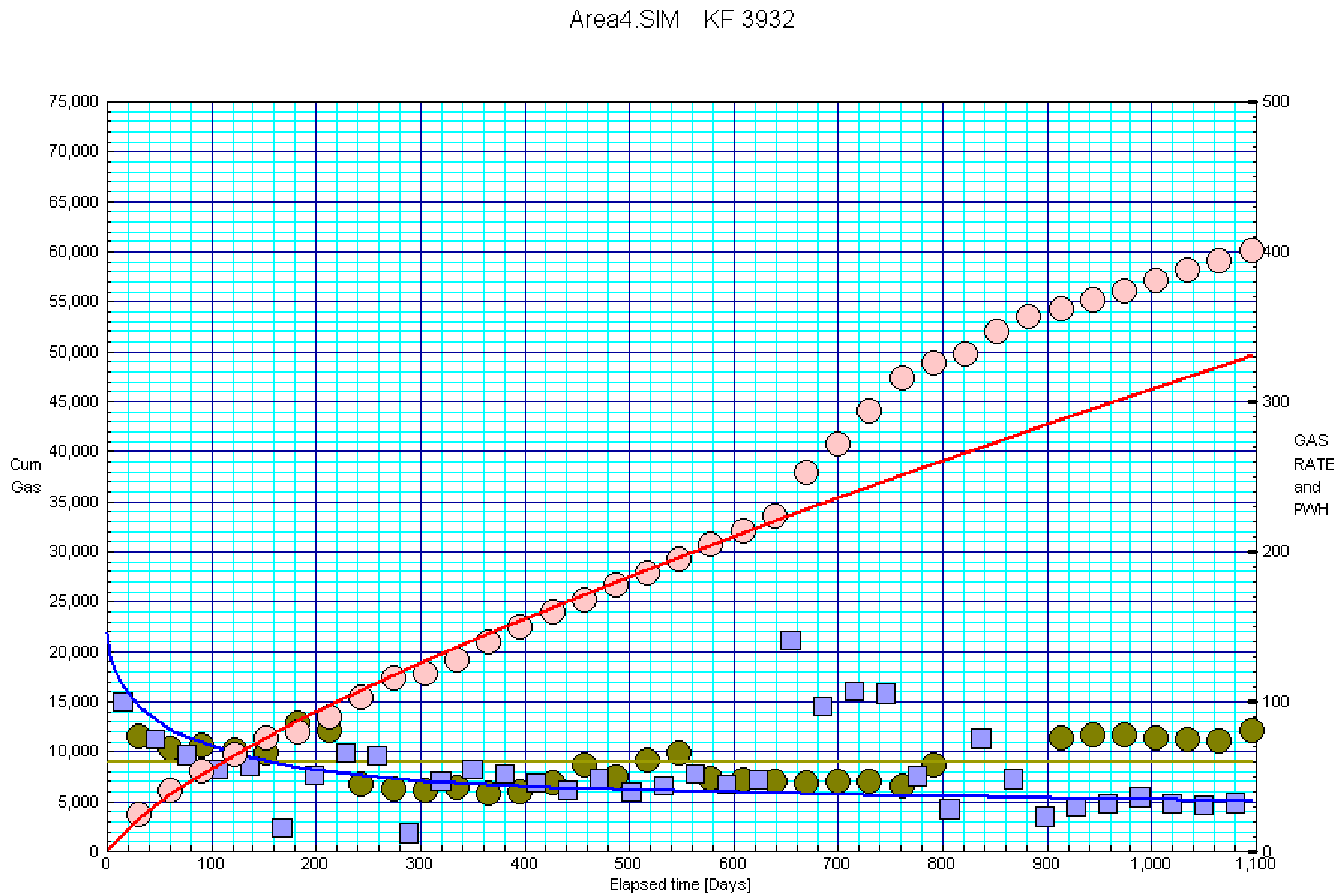

Figure 9 – History Match for Area 4

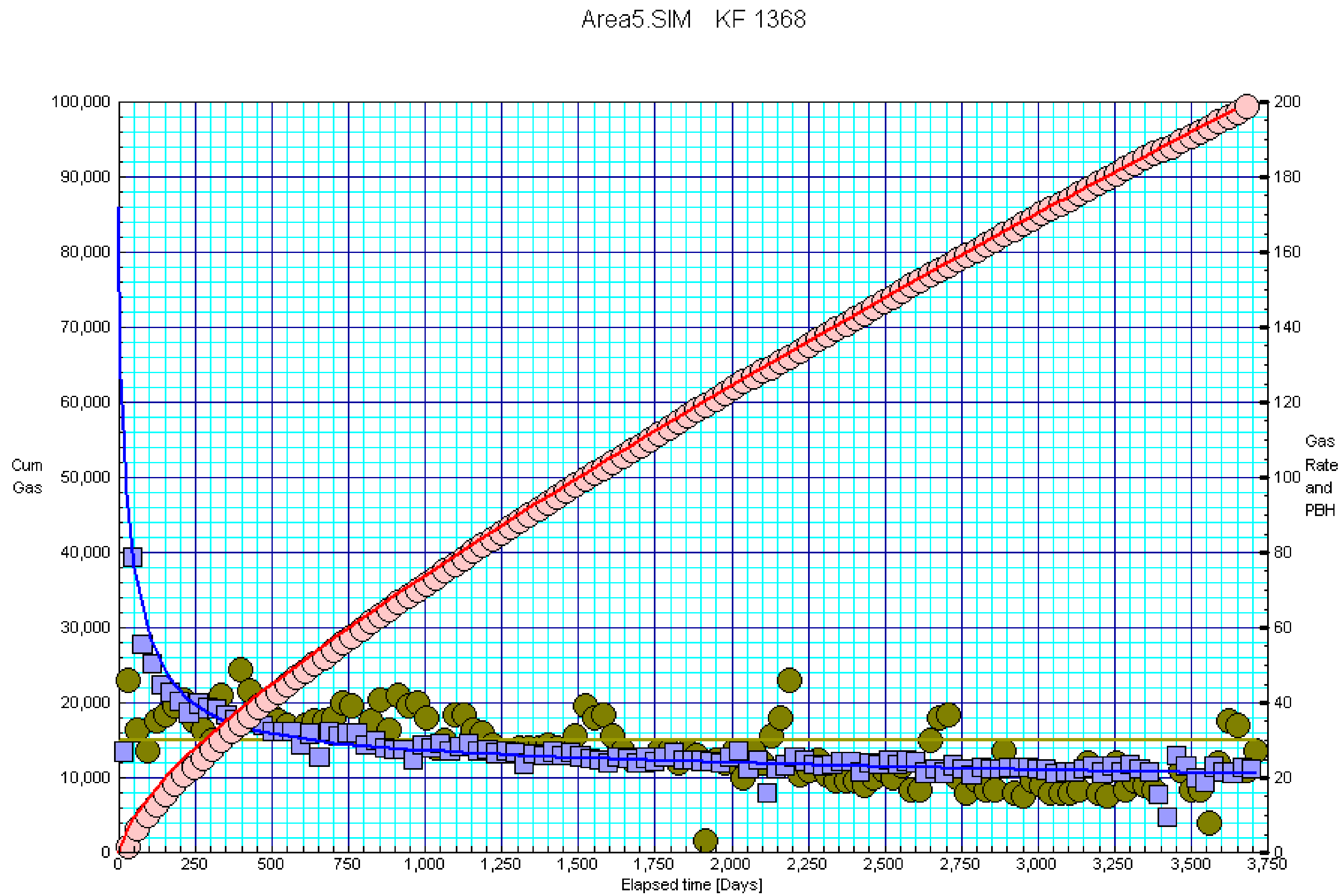

Figure 10 – History Match for Area 5

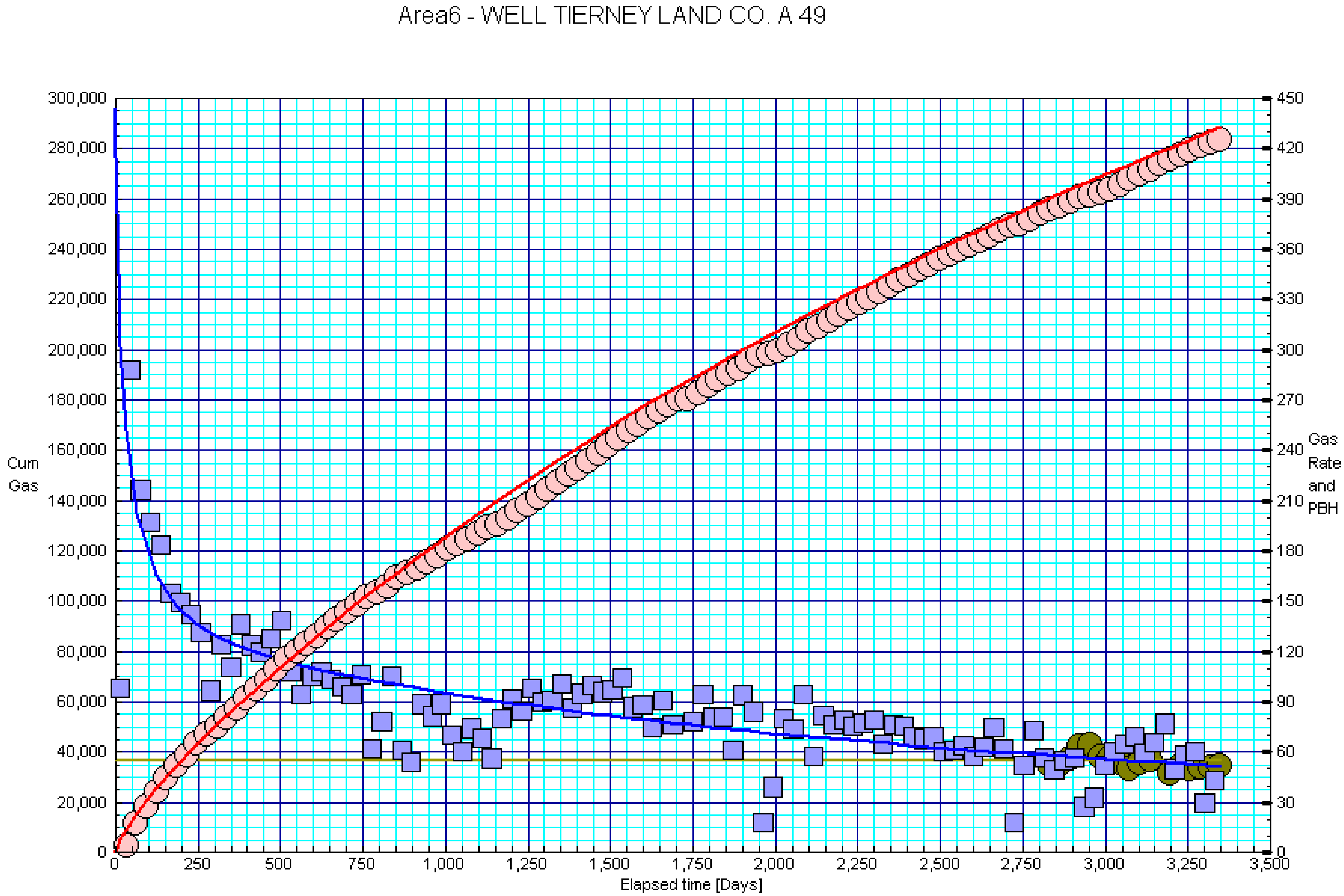

Figure 11 – History Match for Area 6

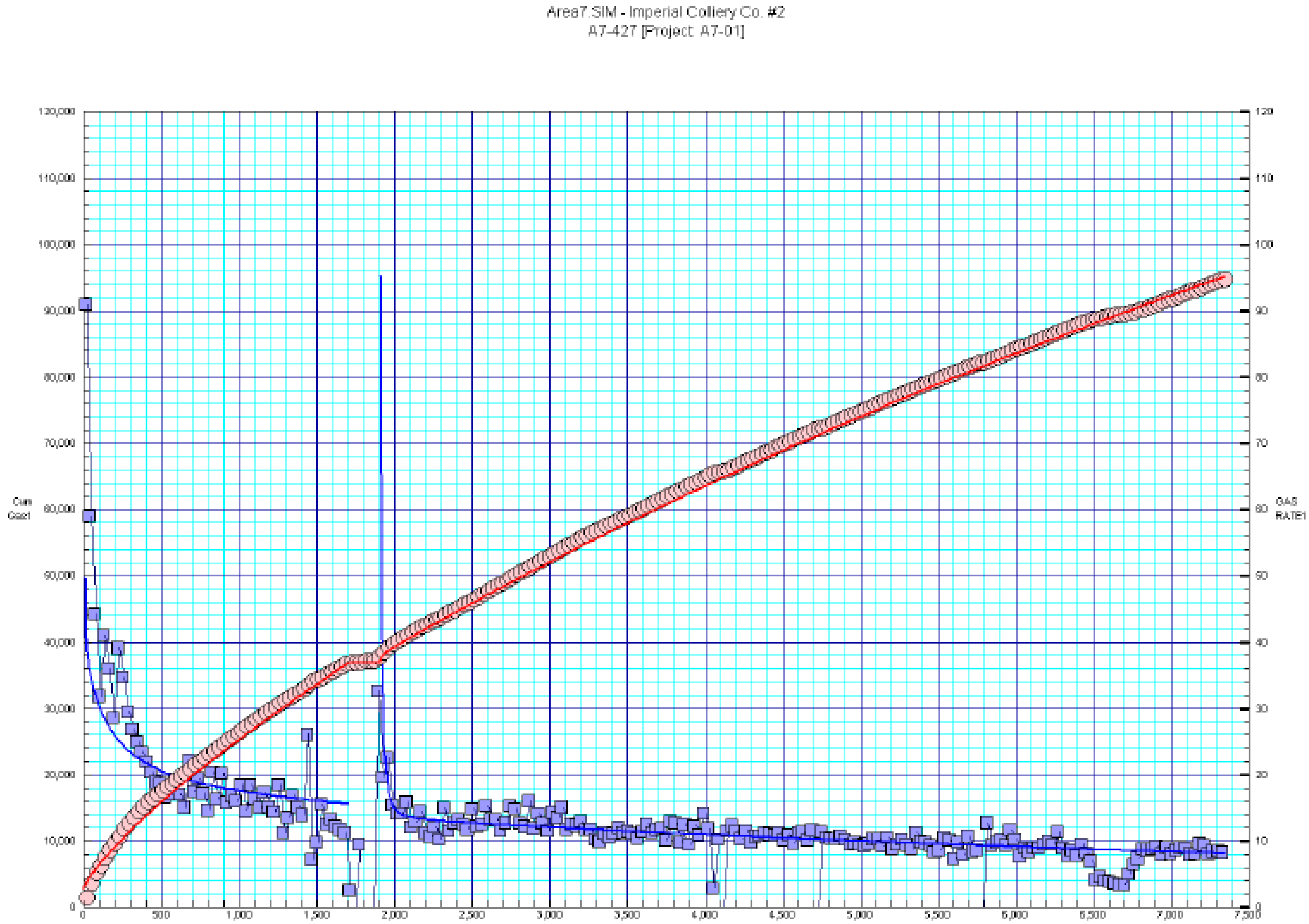

Figure 12 – History March for Area 7

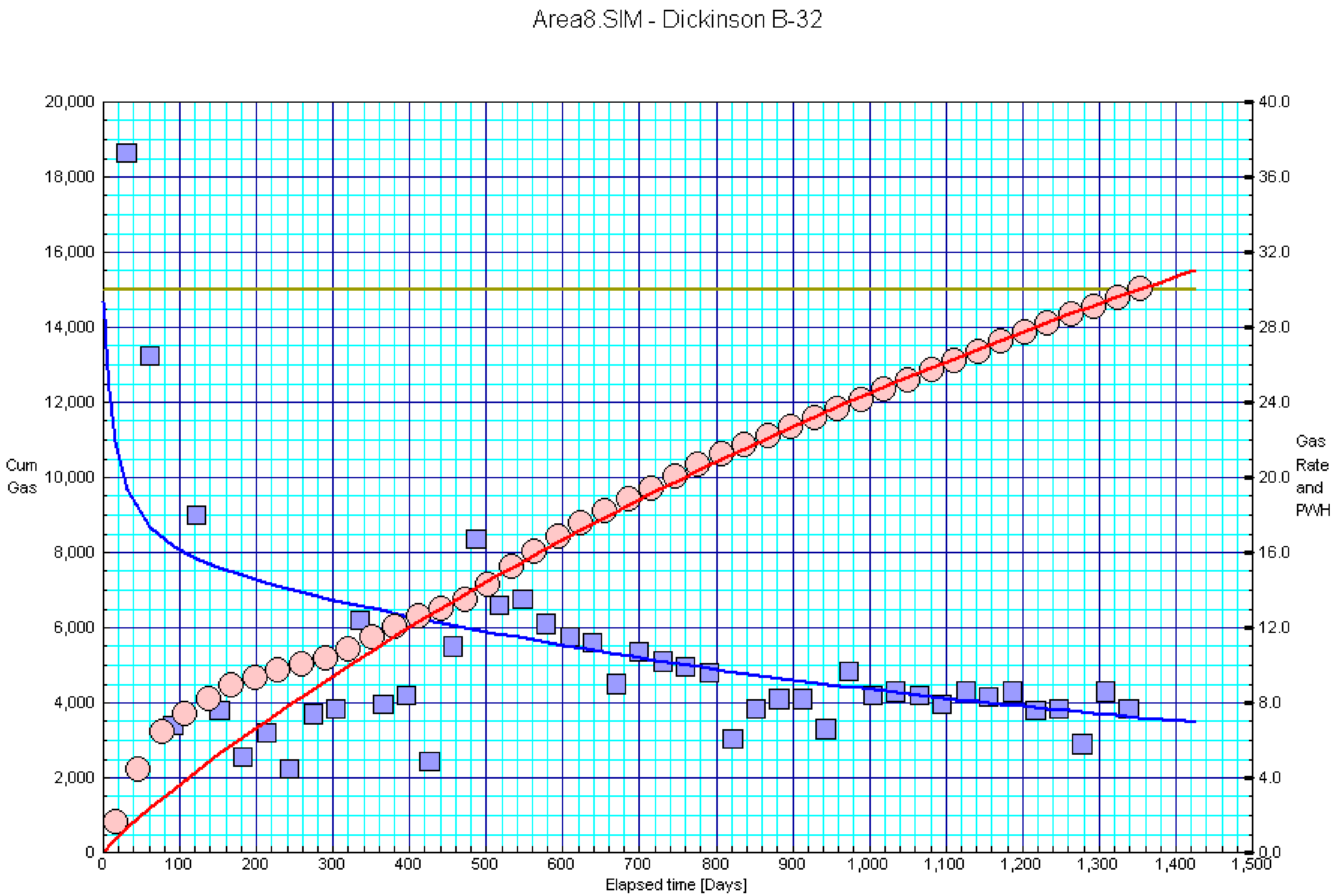

Figure 13 – History Match for Area 8

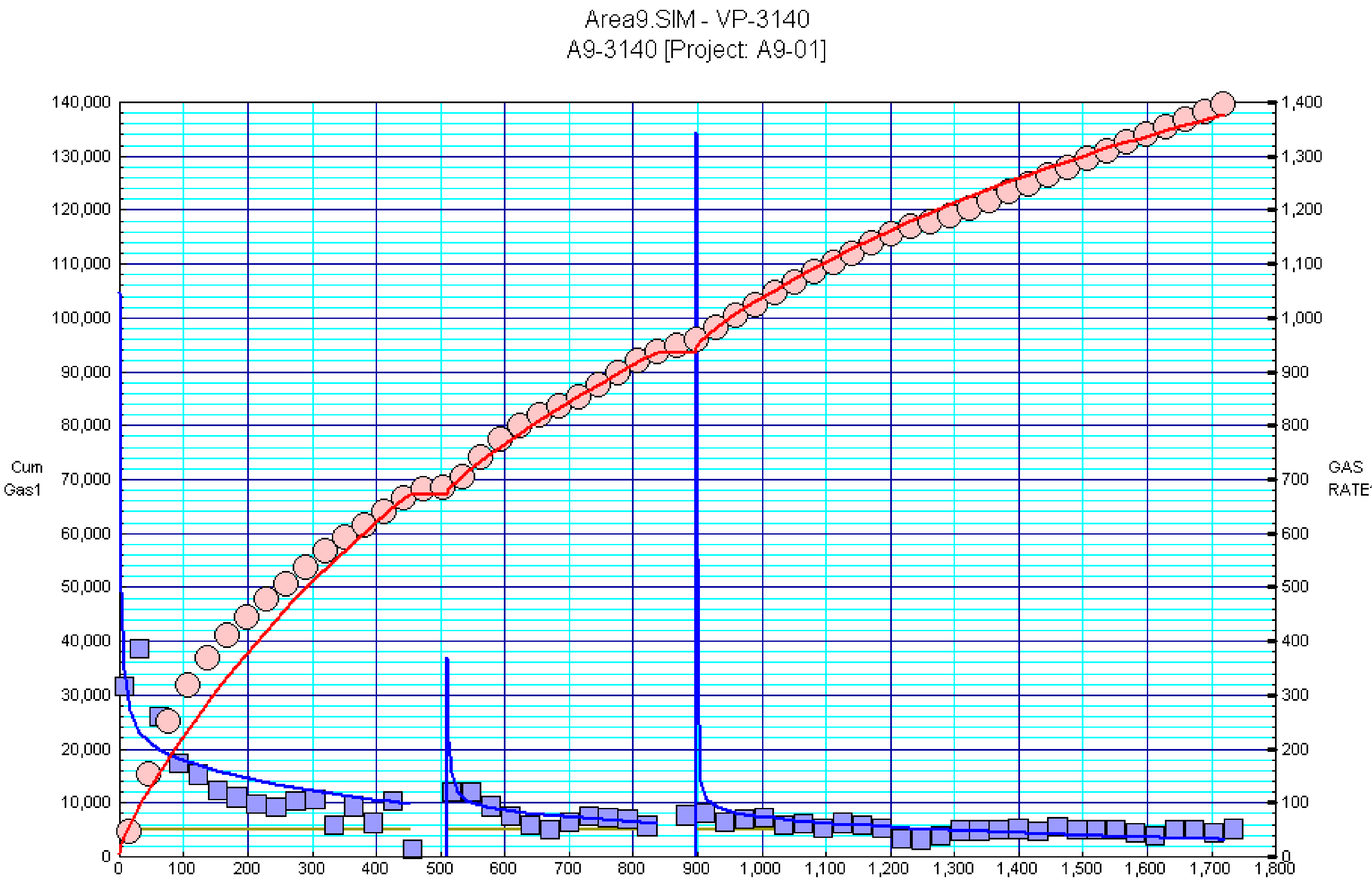

Figure 14 – History Match for Area 9

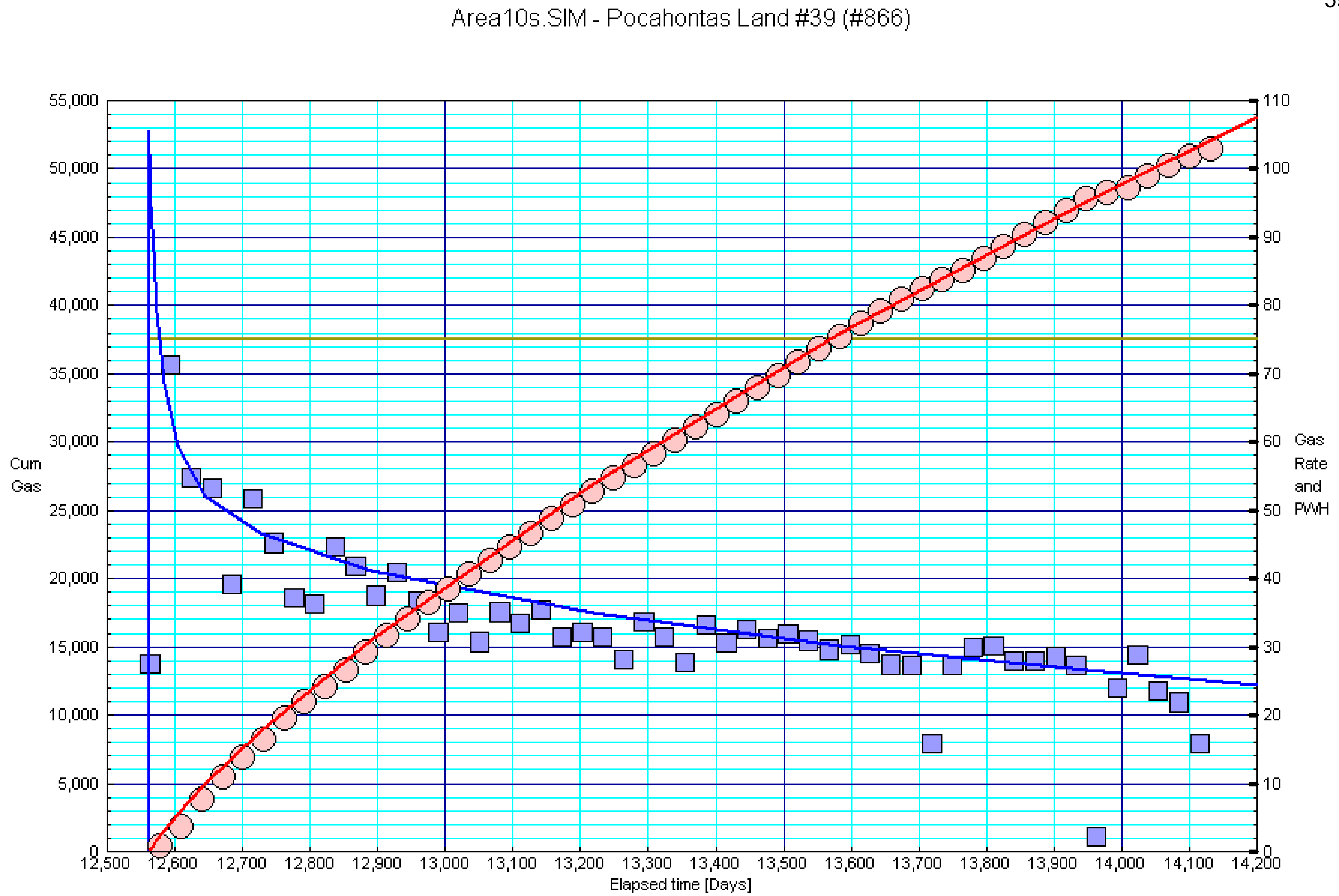

Figure 15 – History Match for Area 10

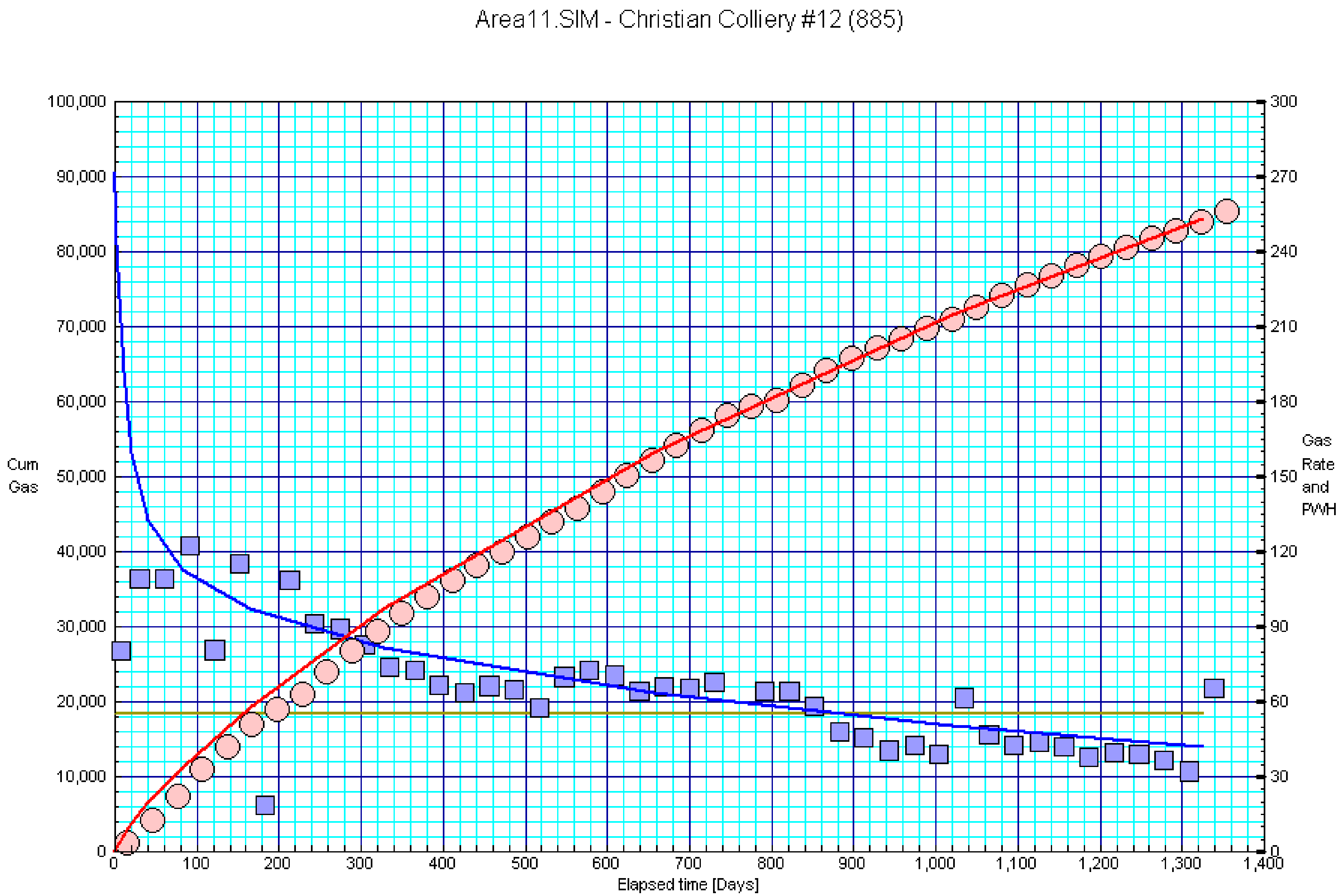

Figure 16 – History Match for Area 11

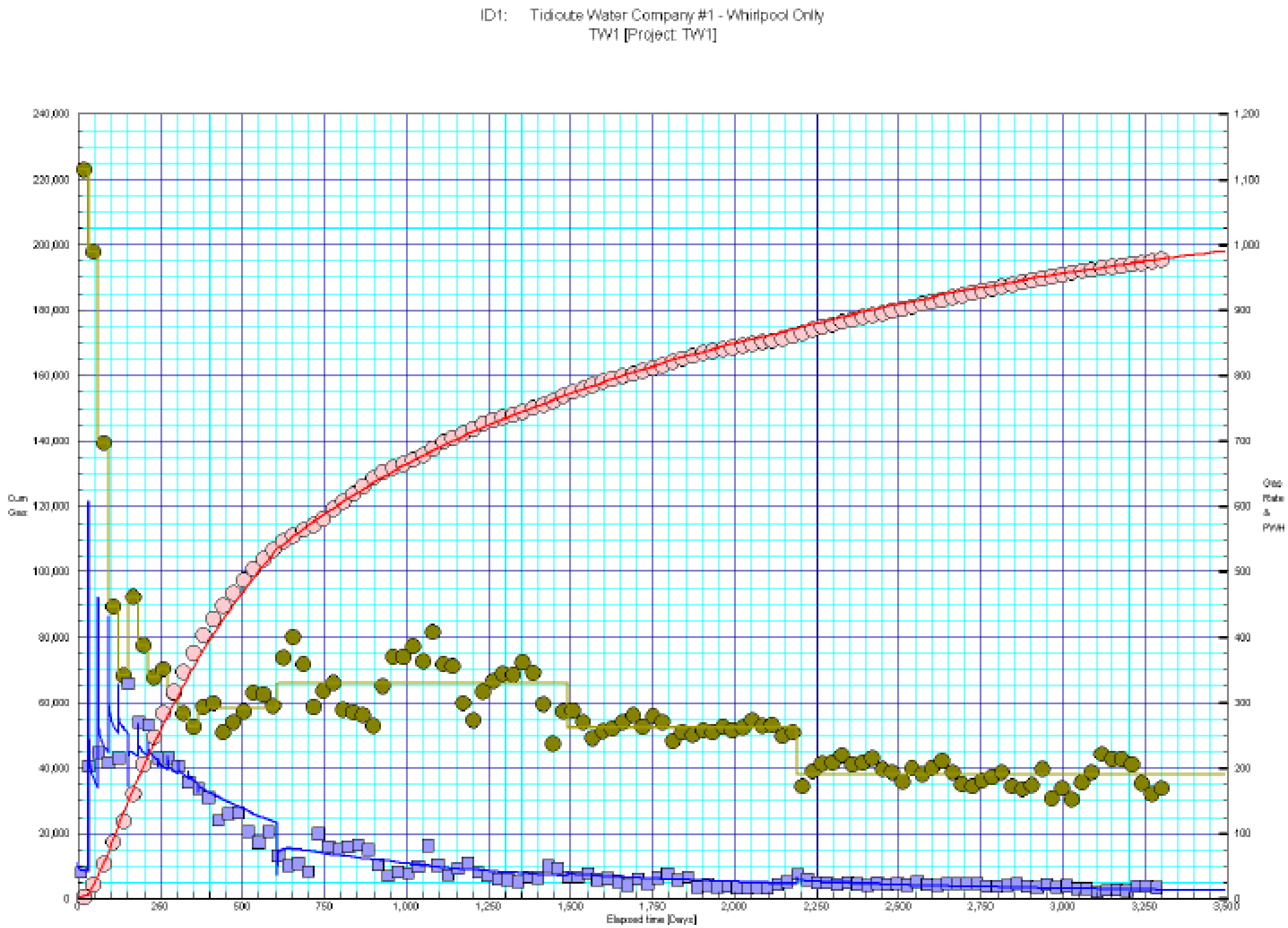

Figure 17 – History Match for Area 12

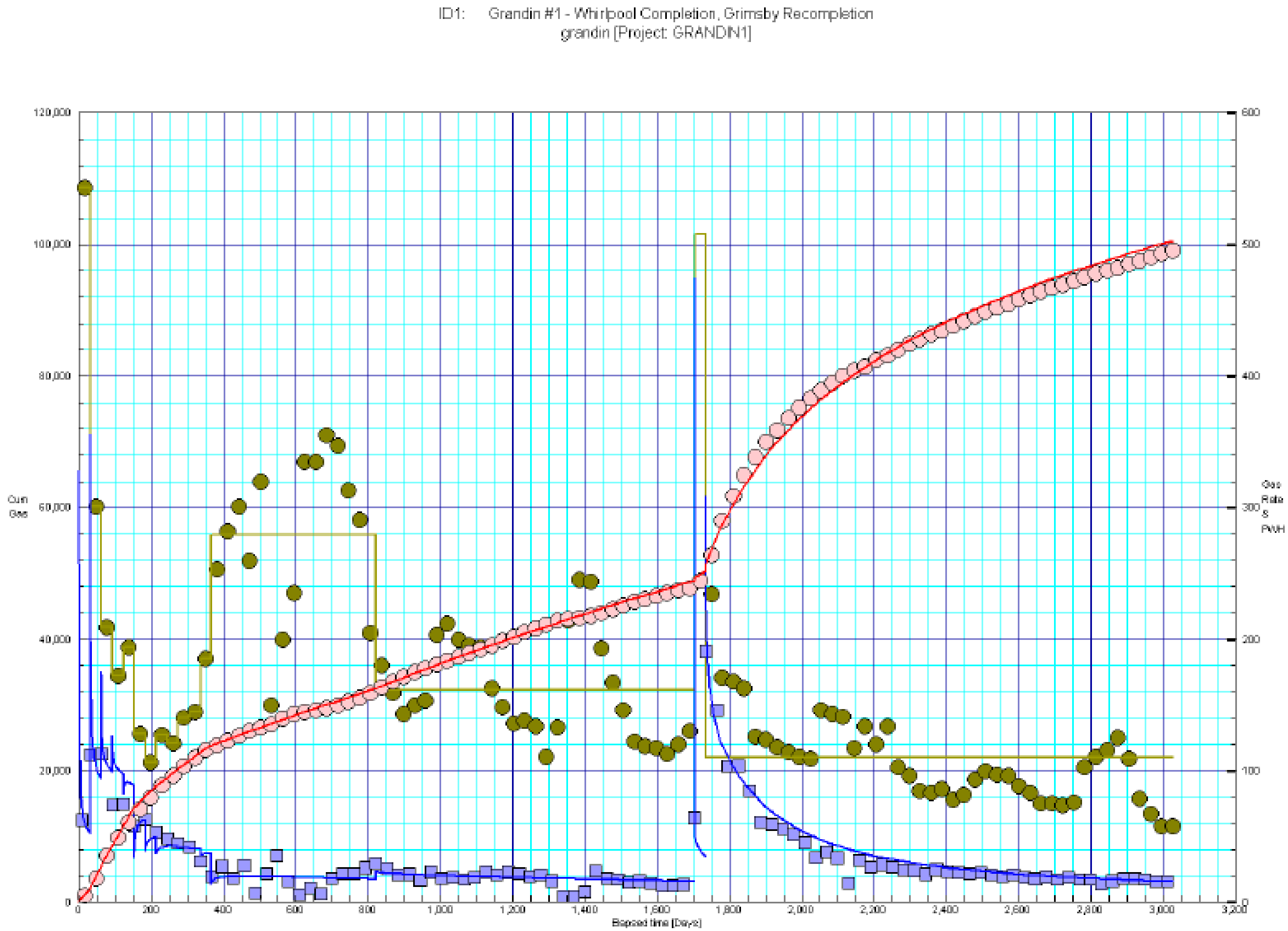

Figure 18 – History Match for Area 13

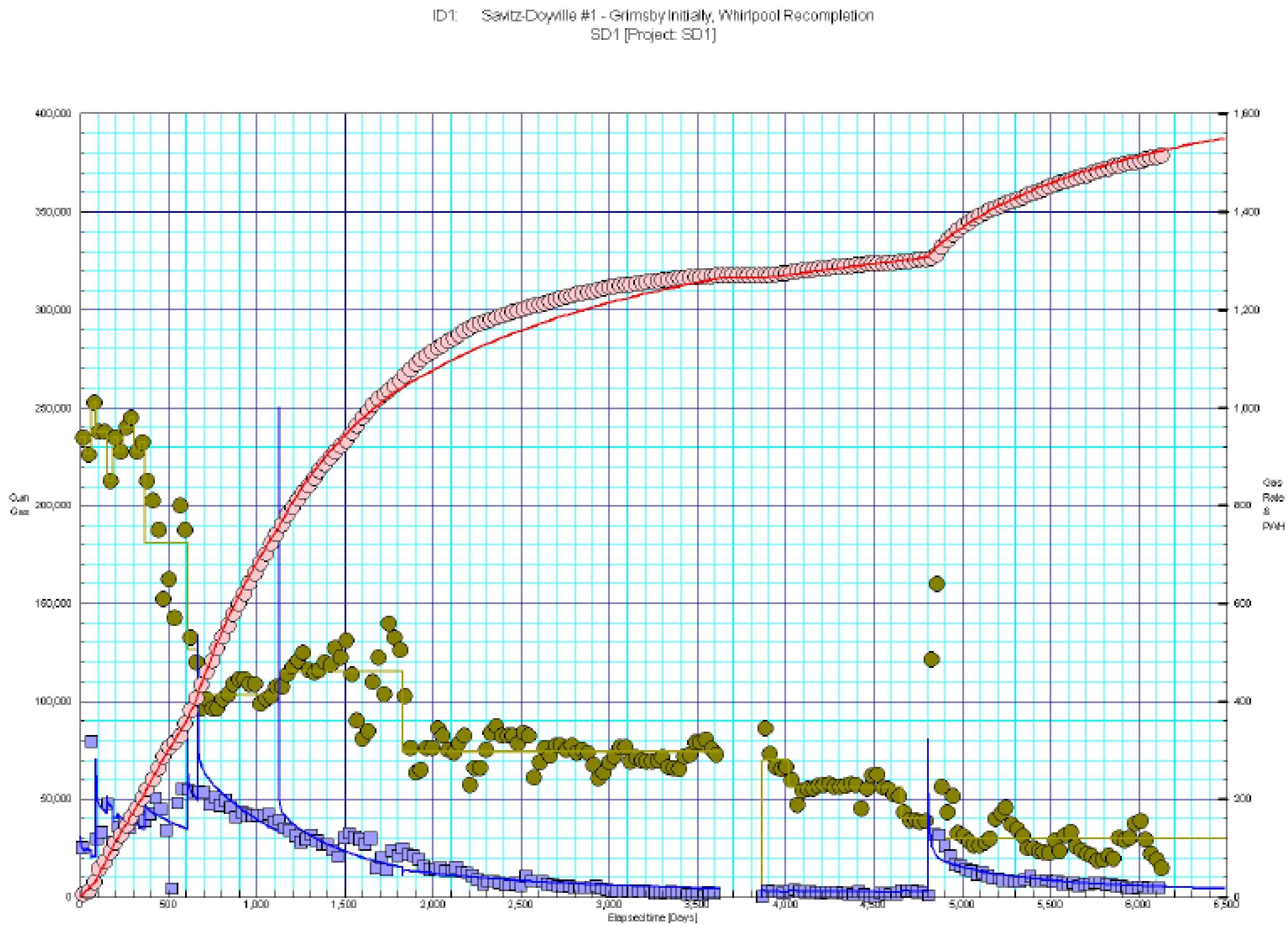

Figure 19 – History Match for Area 14

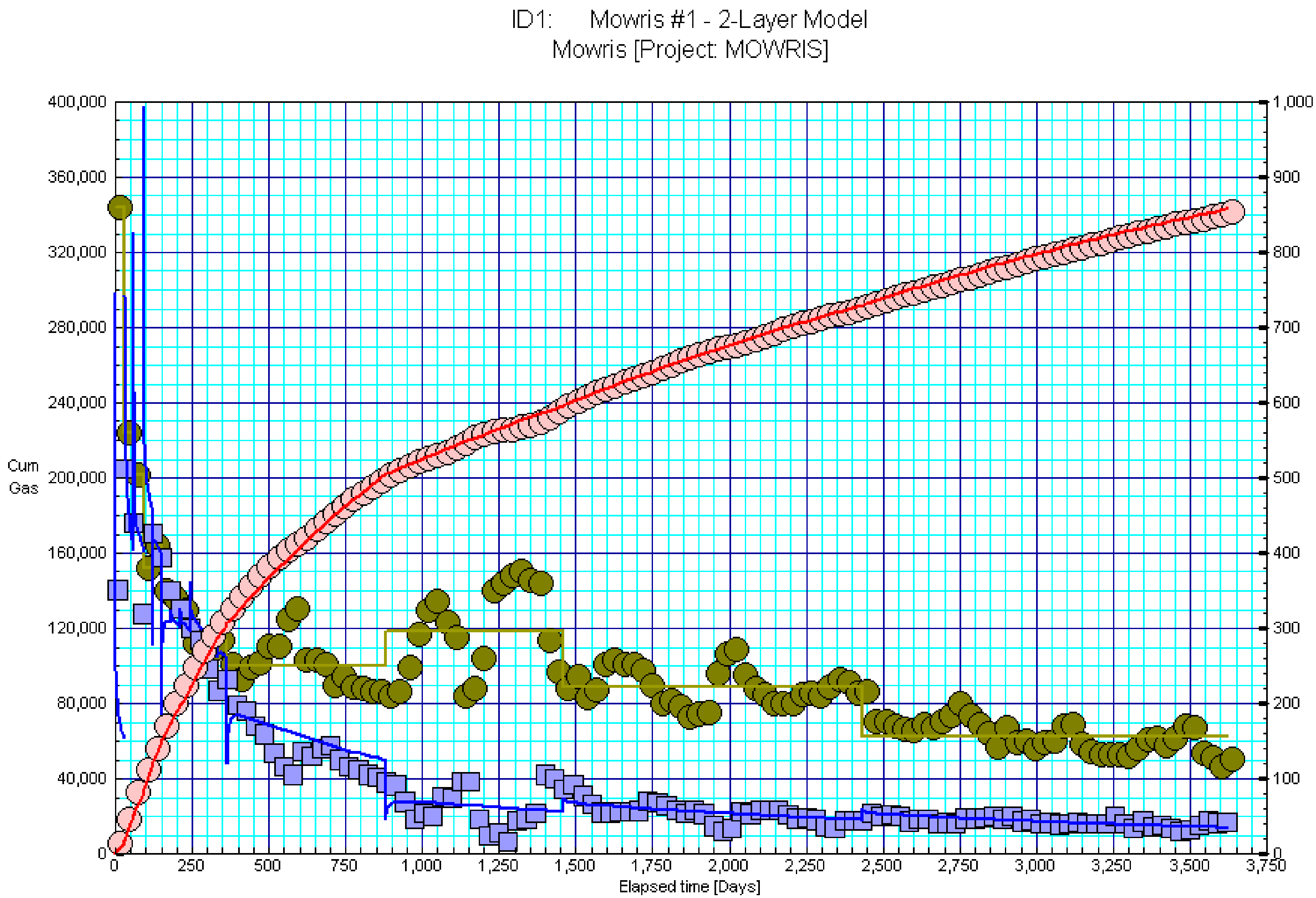

Figure 20 – History Match for Area 15

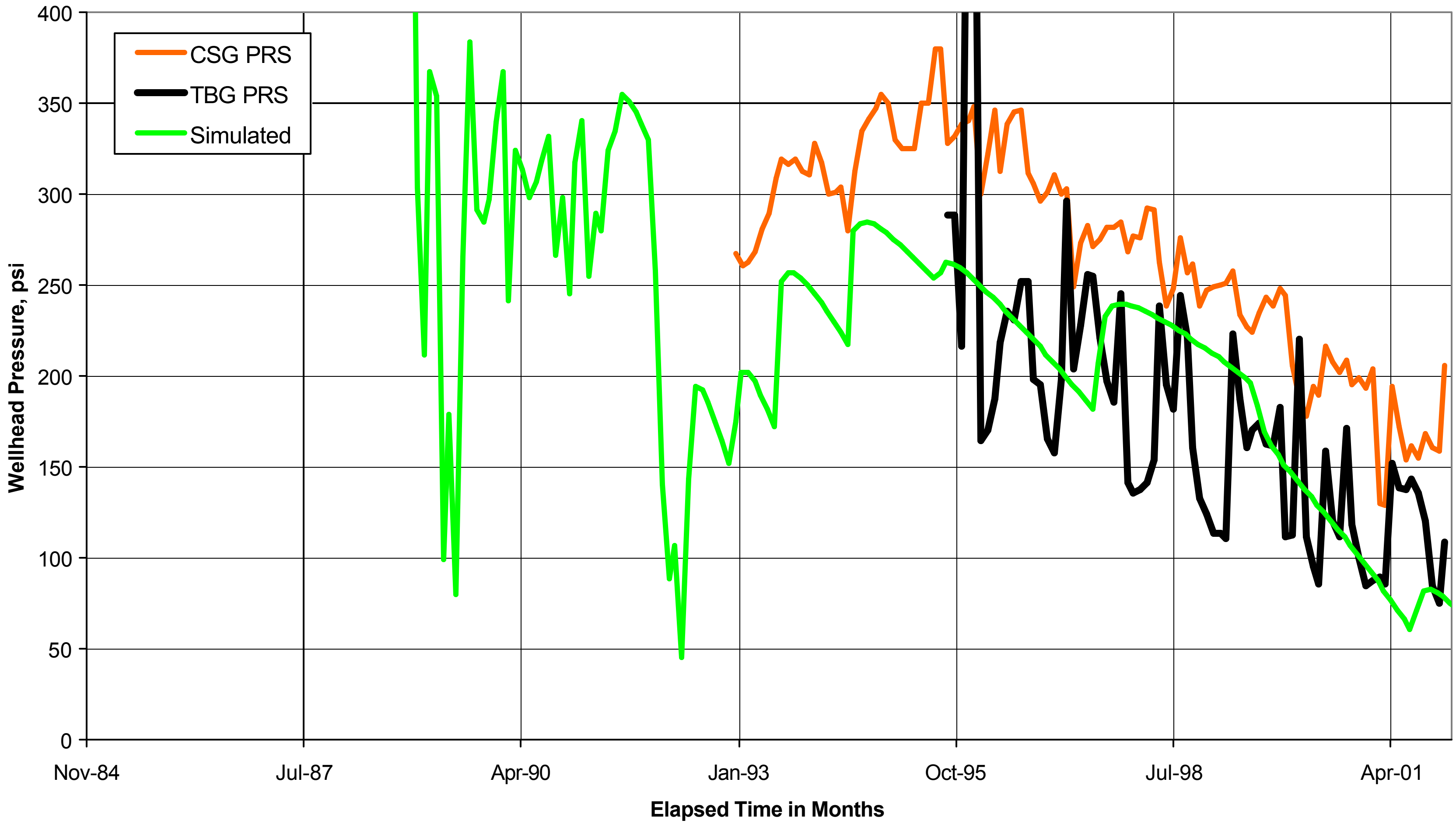

Figure 21 – Comparison of Simulated Wellhead Pressure to Historical Wellhead Pressure

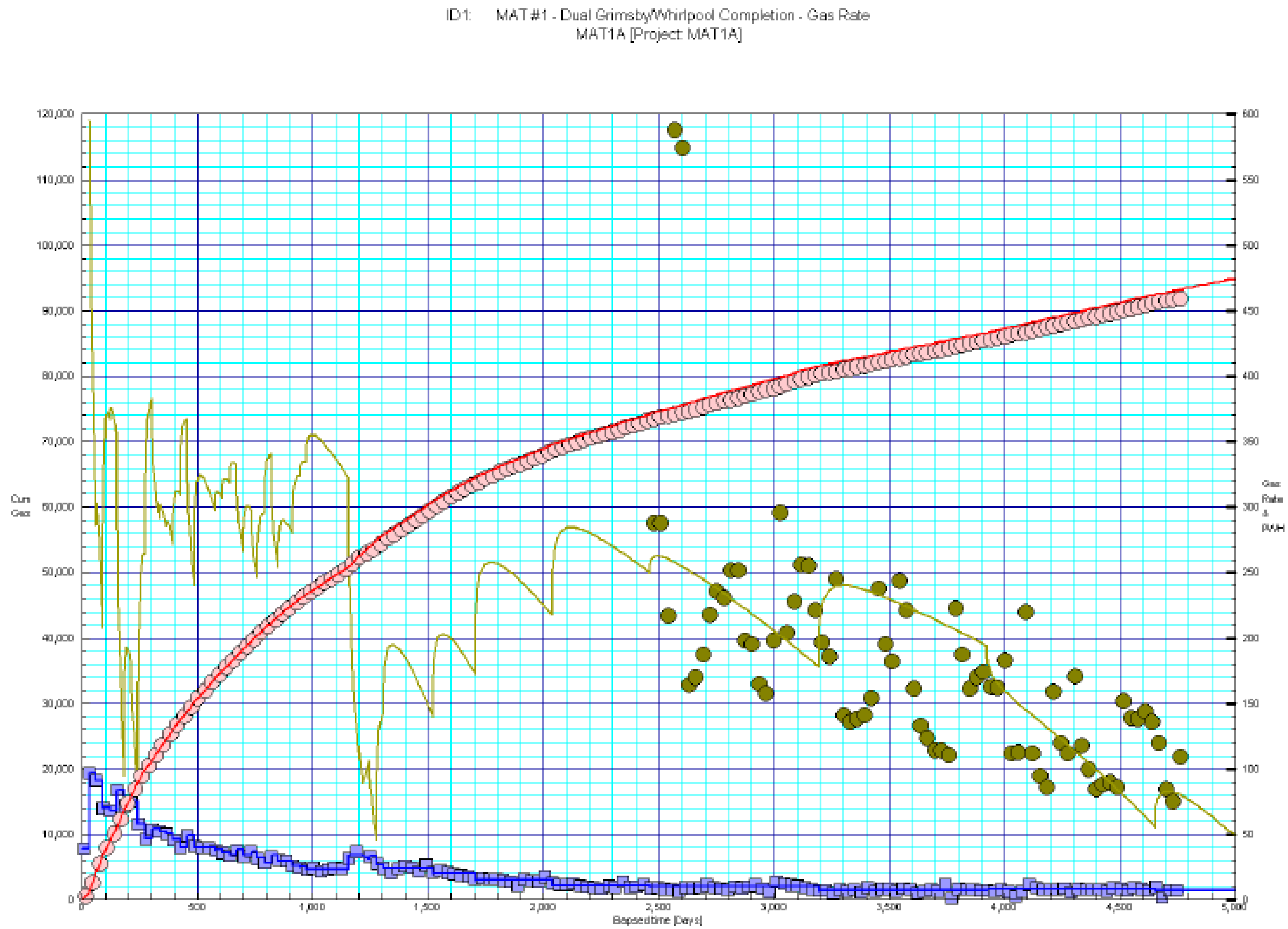

Figure 22 – History Match for Area 16

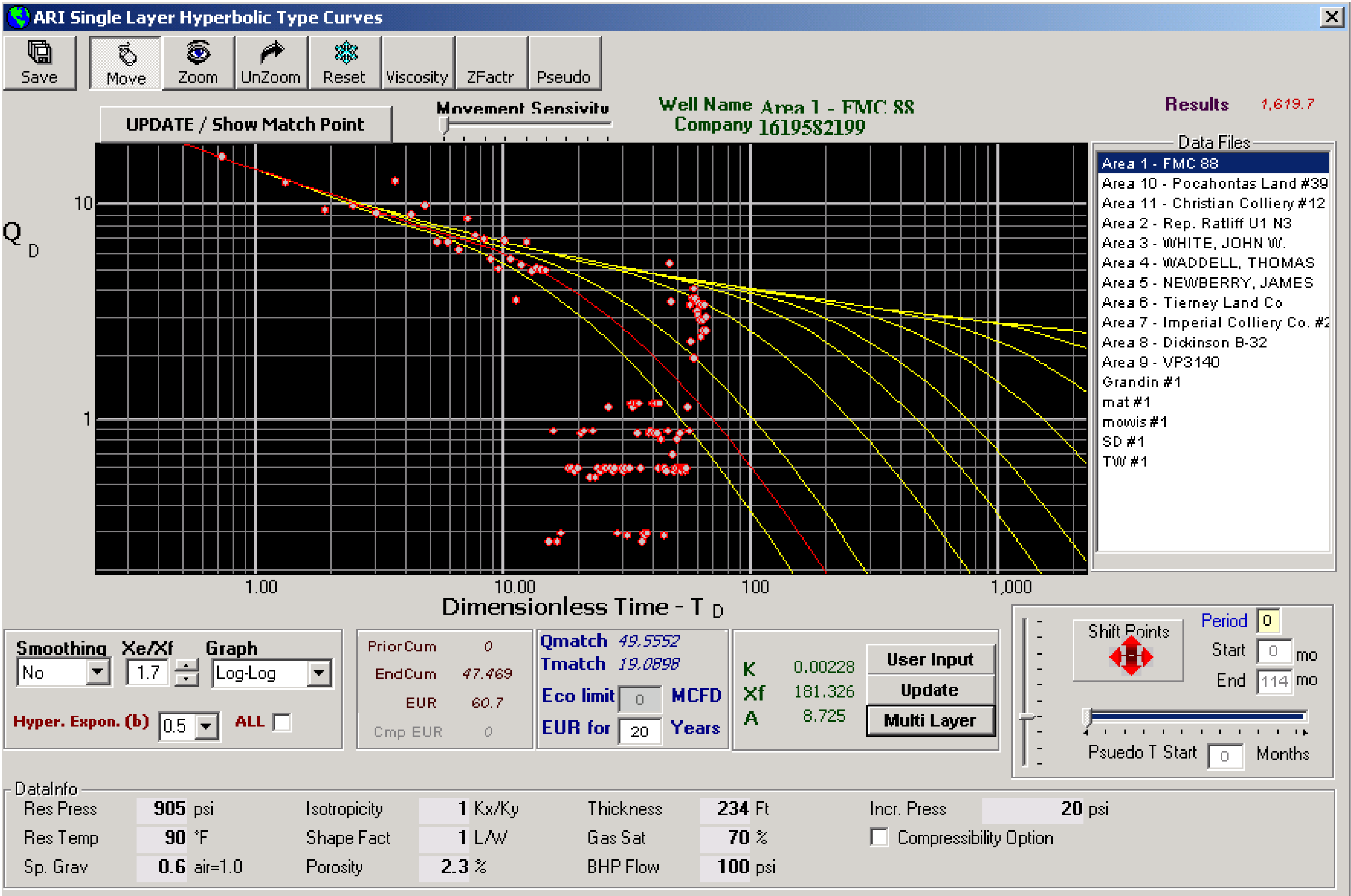

Figure 23 – Area 1 Single Layer Type Curve Match

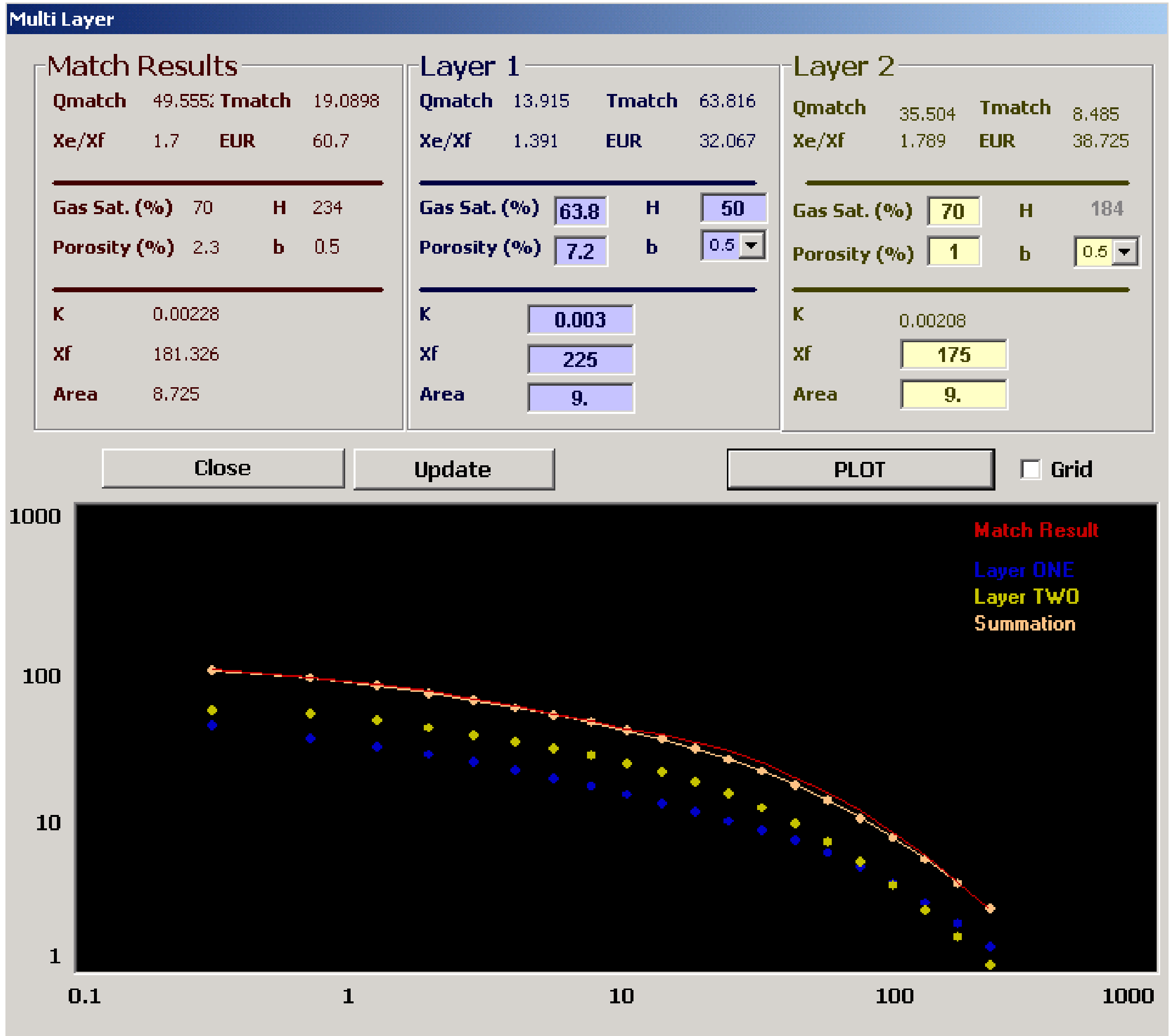

Figure 24 – Area 1 Multiple Layer Type Curve Match Results

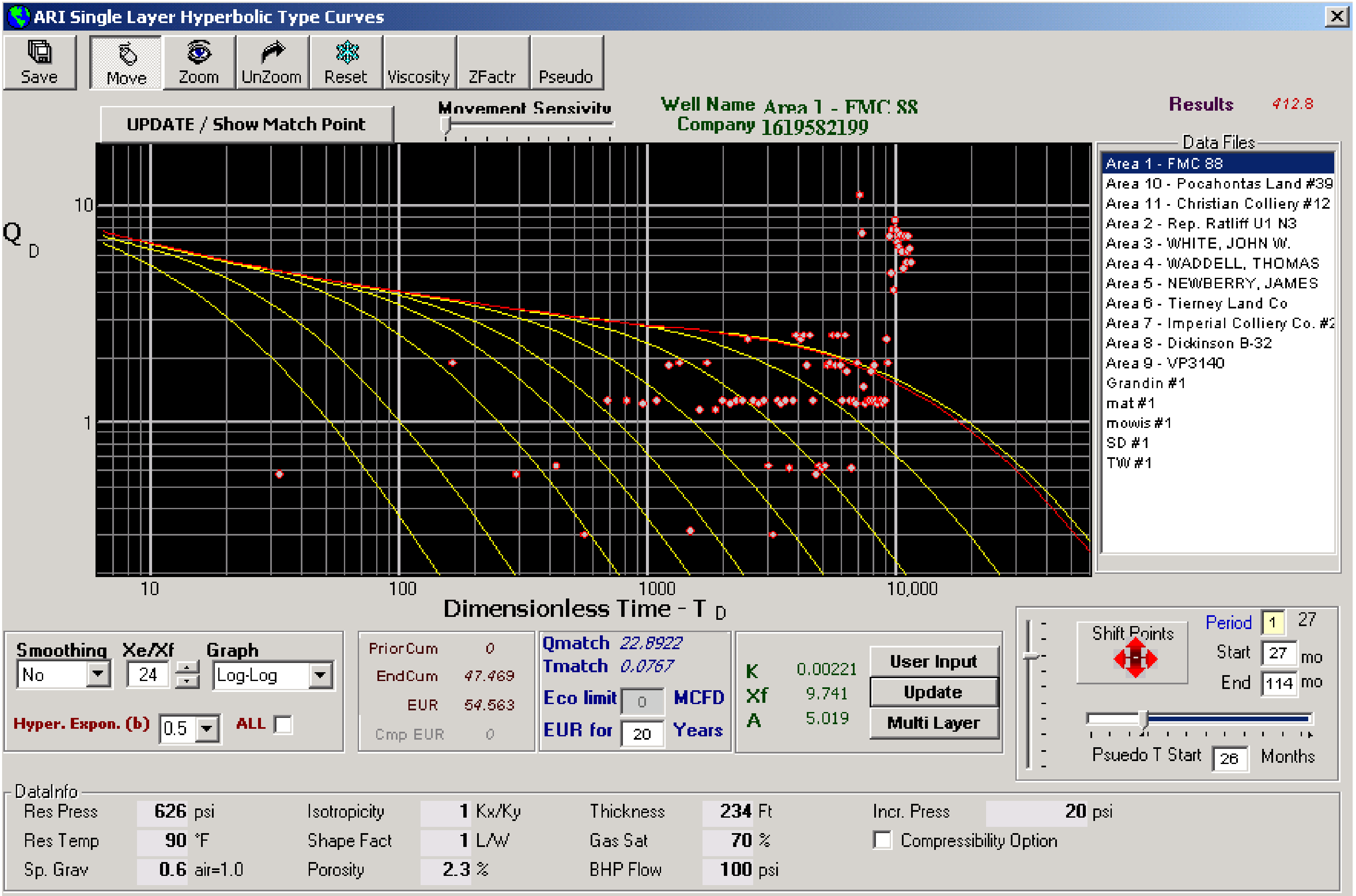

Figure 25 – Area 1 Restart Single Layer Type Curve Match

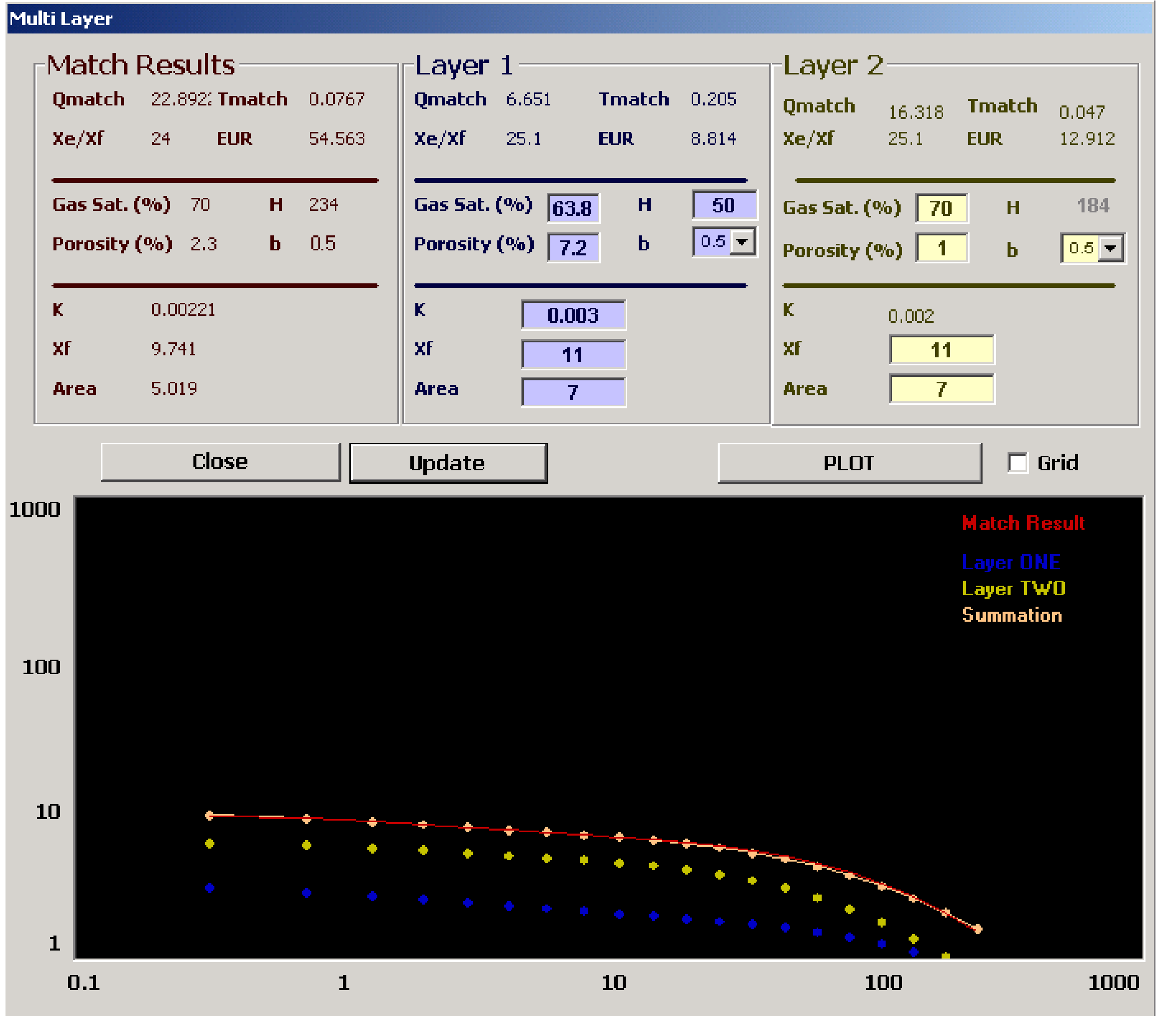

Figure 26 – Area 1 Restart Multiple Layer Type Curve Match Results

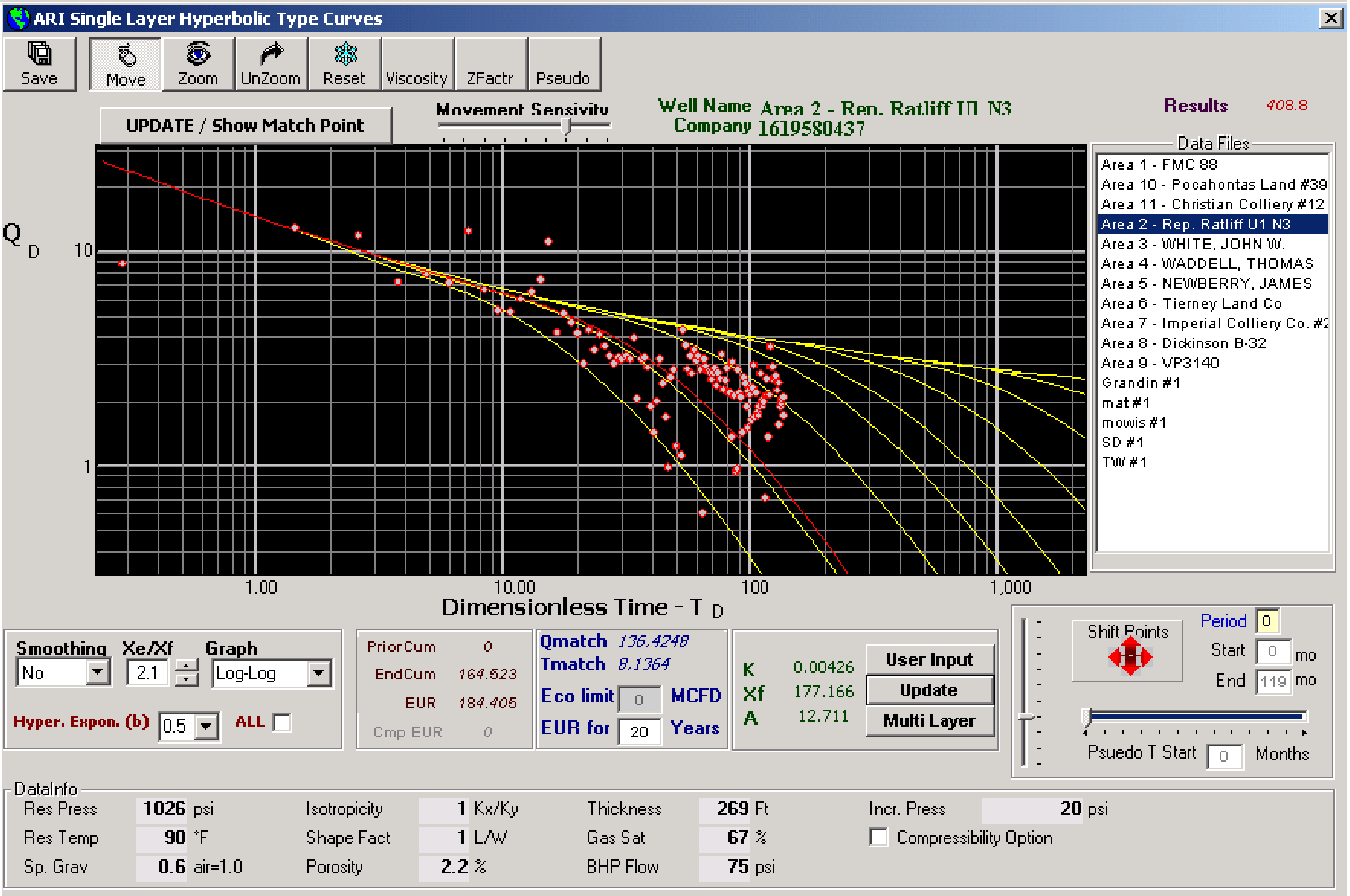

Figure 27 – Area 2 Single Layer Type Curve Match

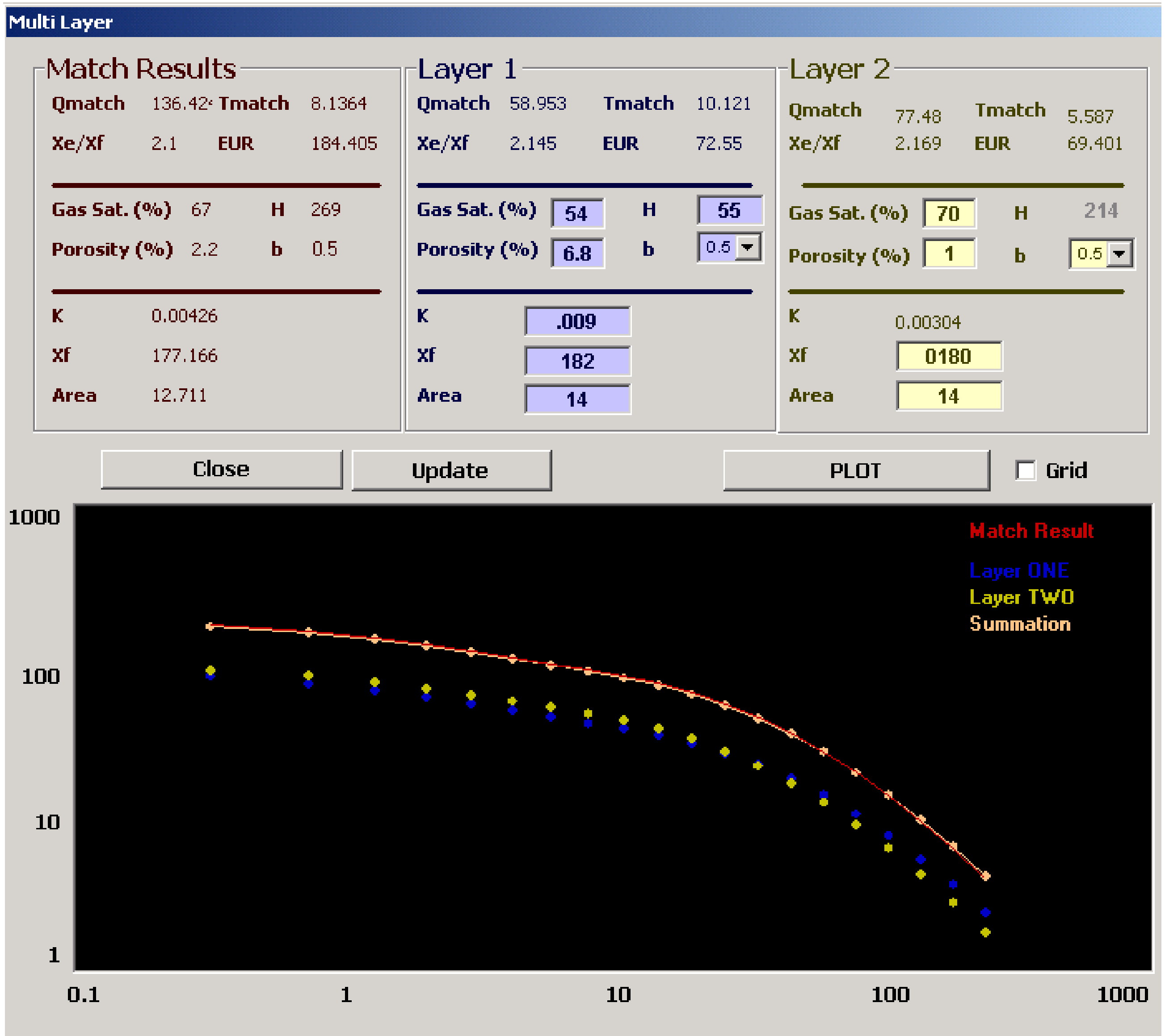

Figure 28 – Area 2 Multiple Layer Type Curve Match Results

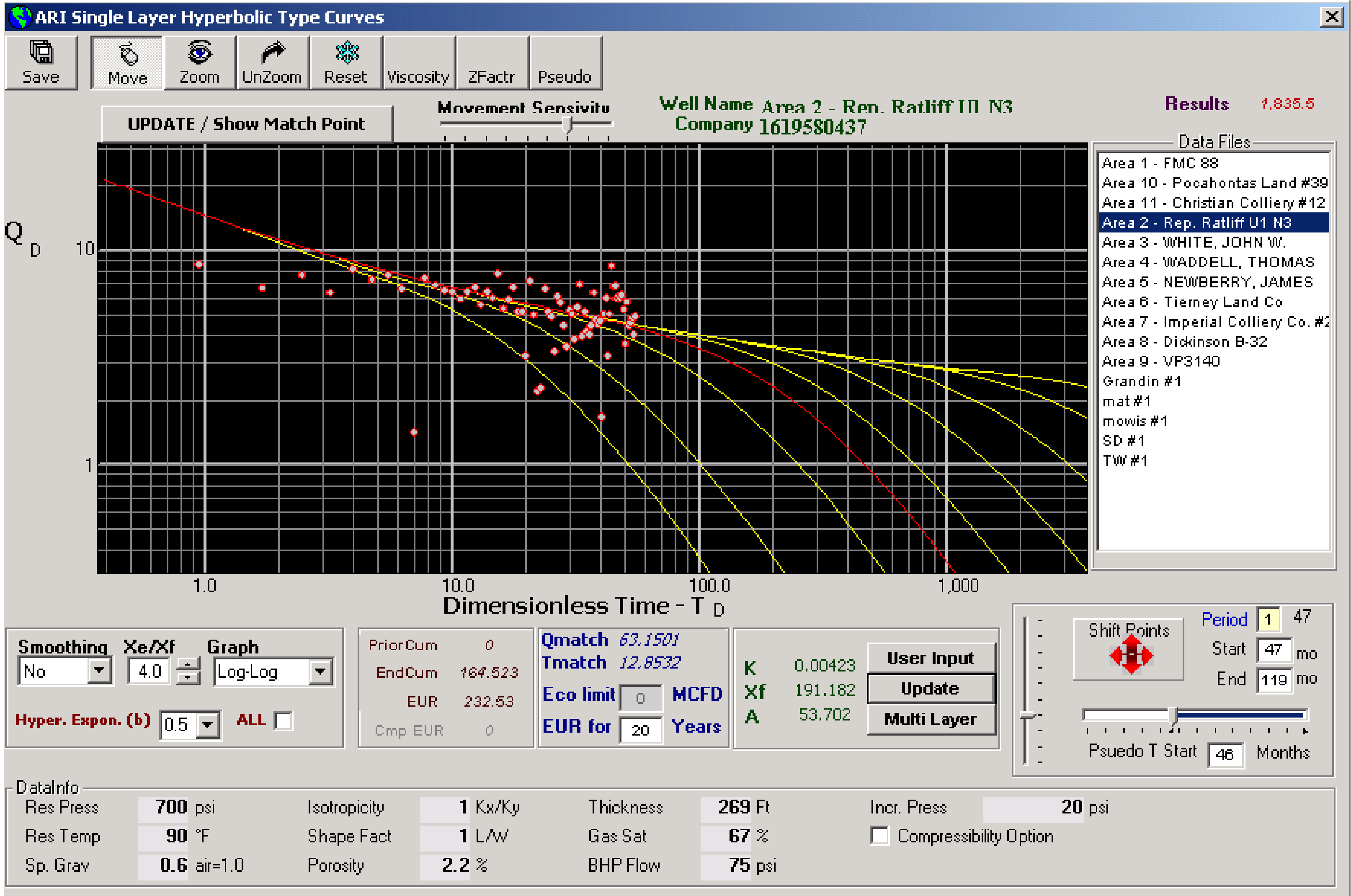

Figure 29 – Area 2 Restart Single Layer Type Curve Match

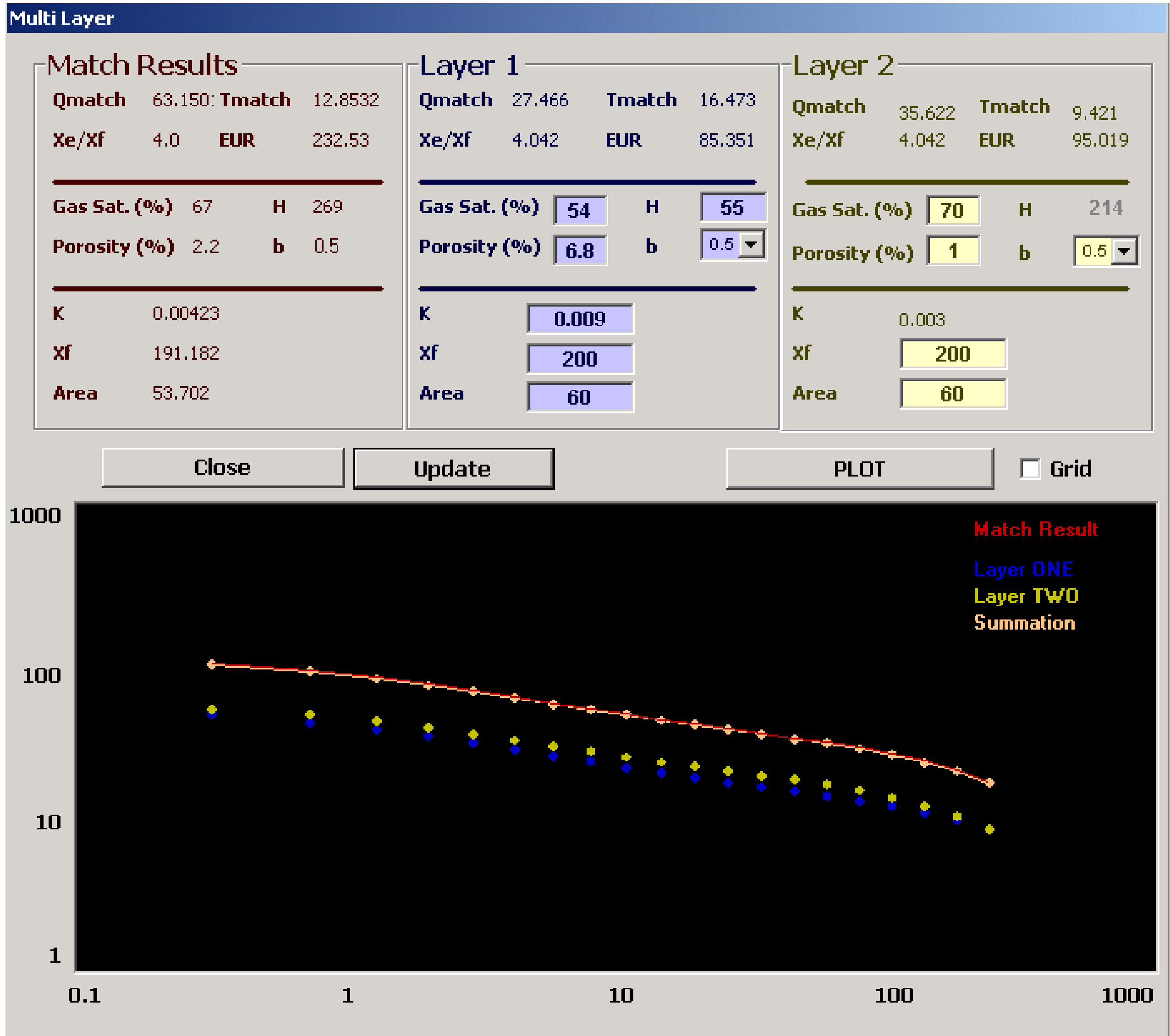

Figure 30 – Area 2 Restart Multiple Layer Type Curve Match Results

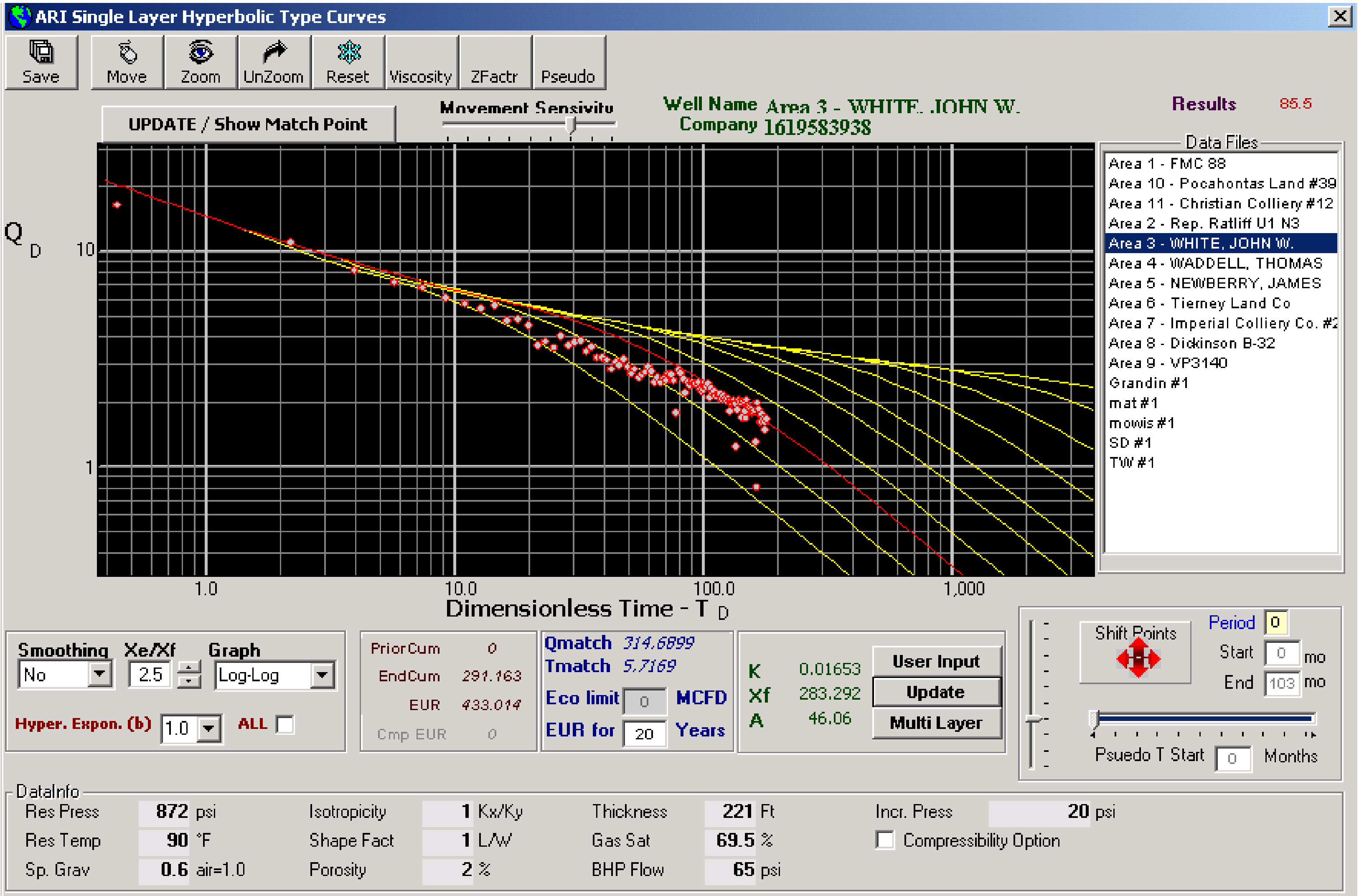

Figure 31 – Area 3 Single Layer Type Curve Match

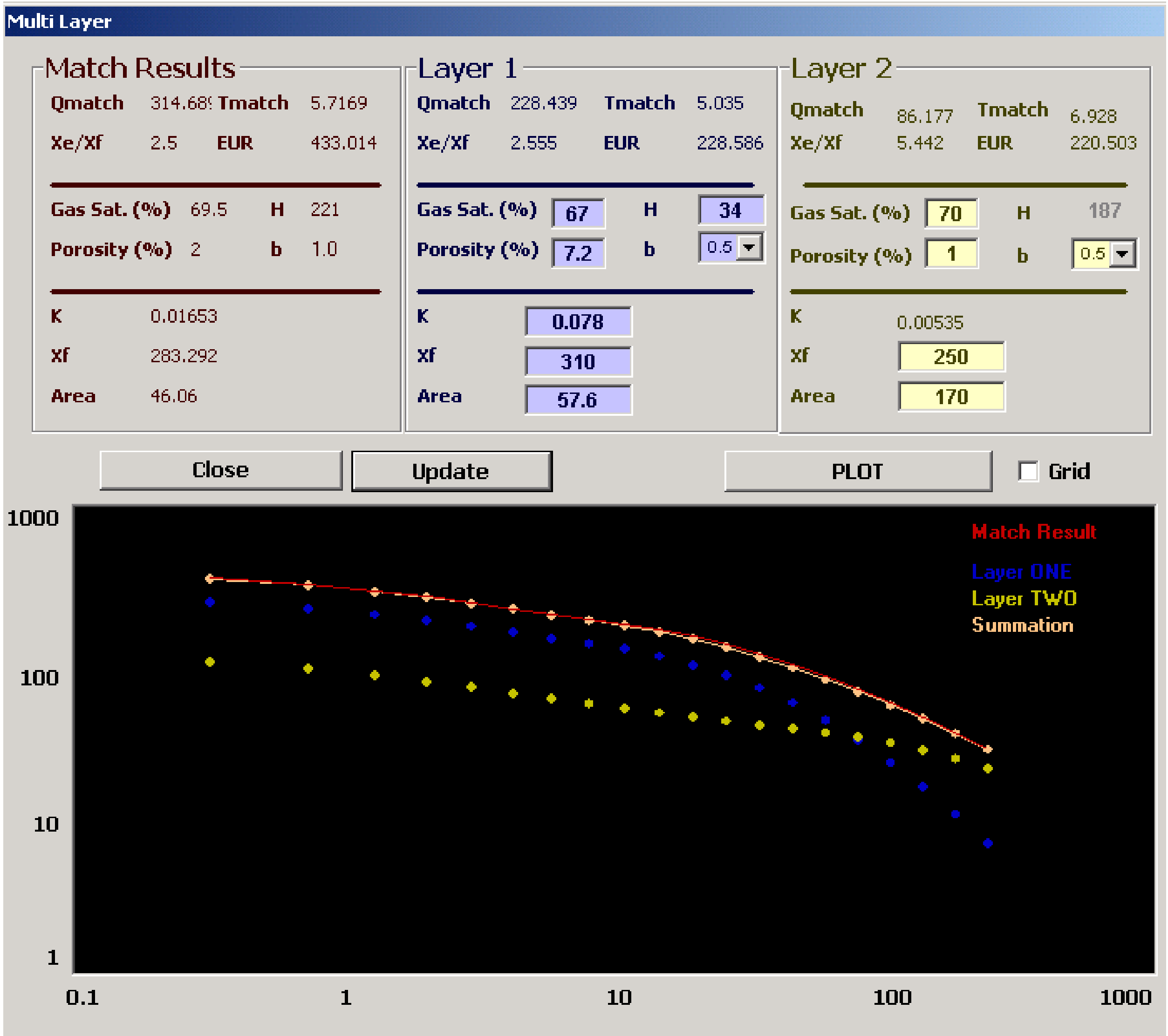

Figure 32 – Area 3 Multiple Layer Type Curve Match Results

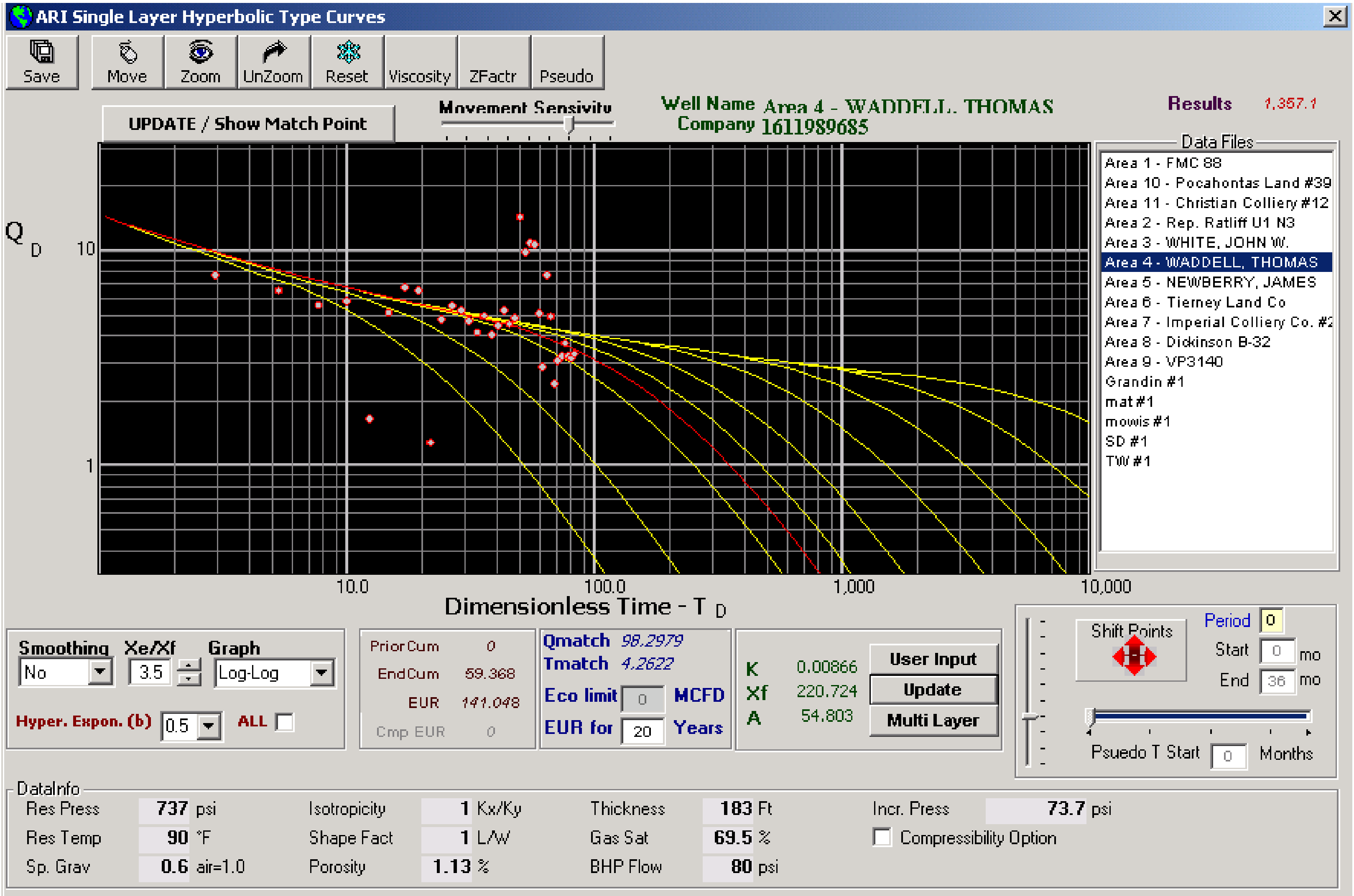

Figure 33 – Area 4 Single Layer Type Curve Match

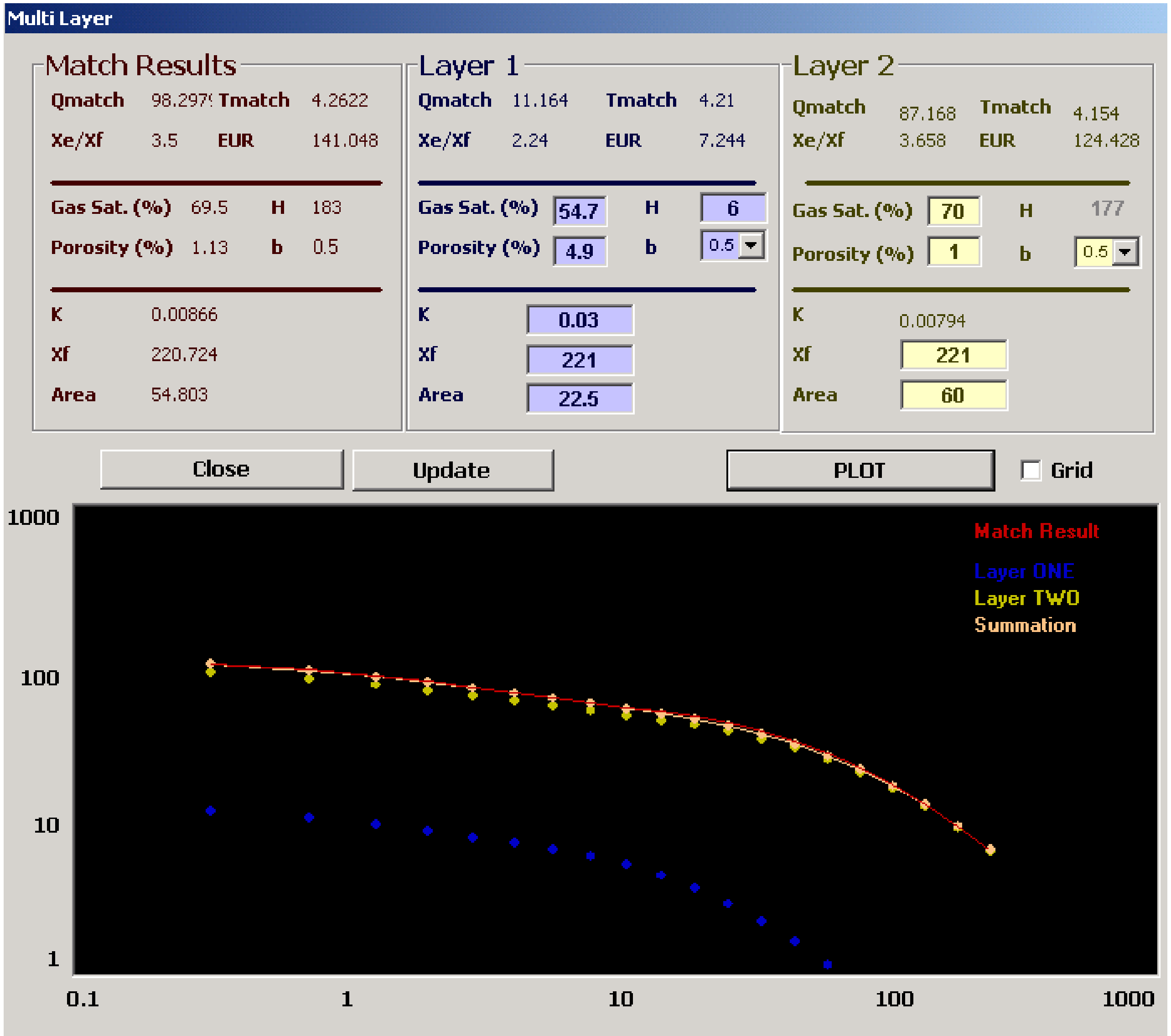

Figure 34 – Area 4 Multiple Layer Type Curve Match Results

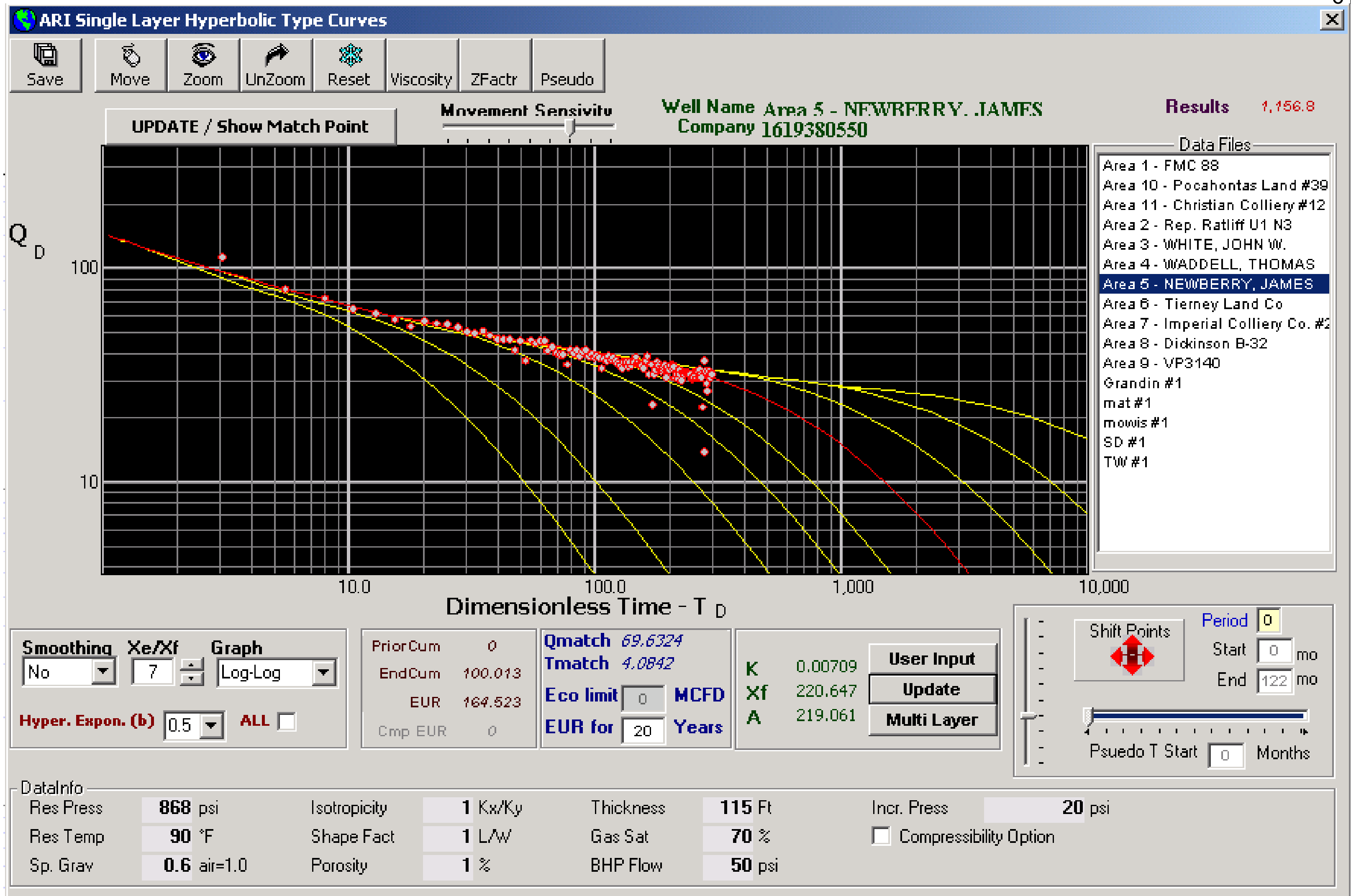

Figure 35 – Area 5 Single Layer Type Curve Match

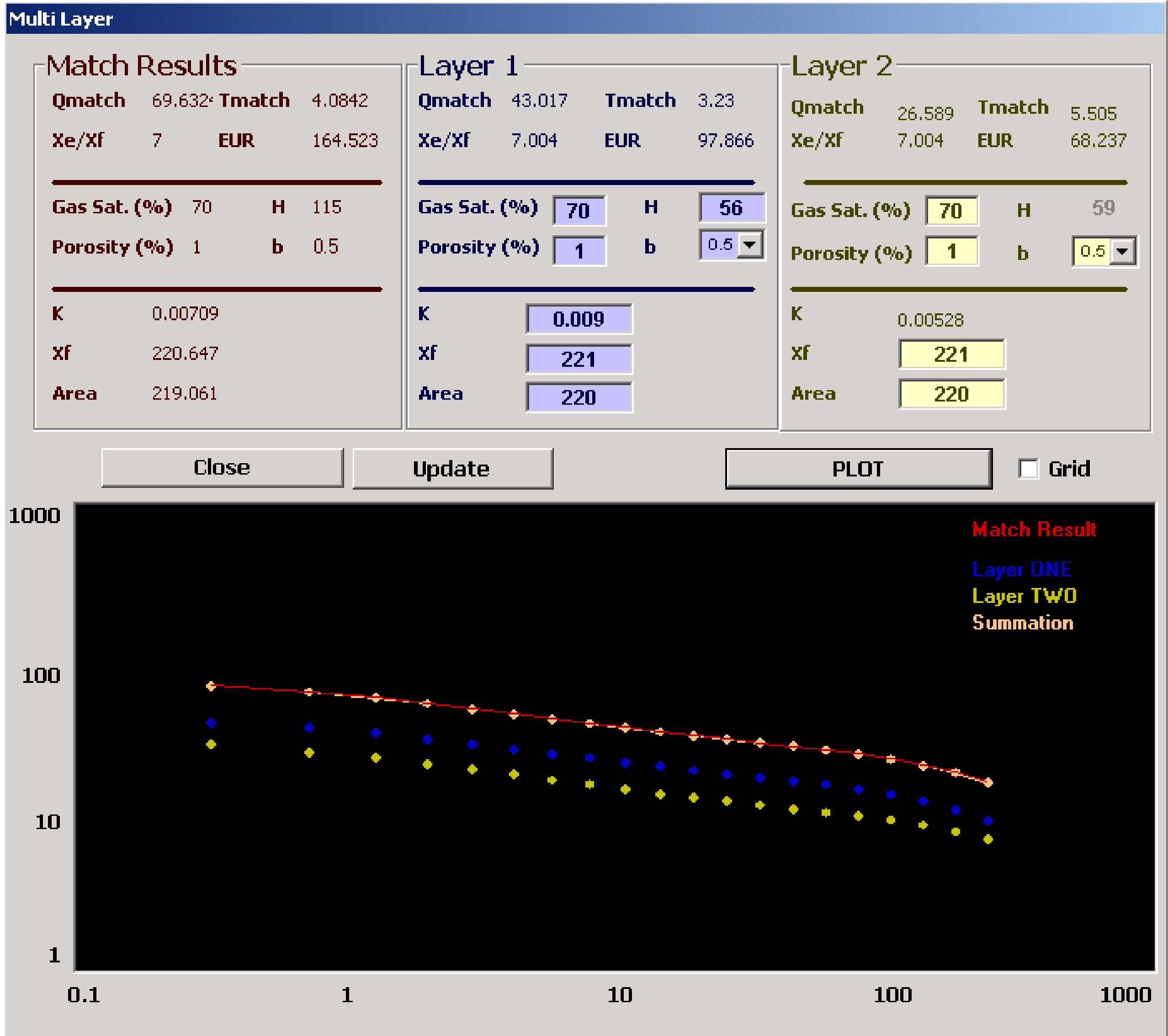

Figure 36 – Area 5 Multiple Layer Type Curve Match Results

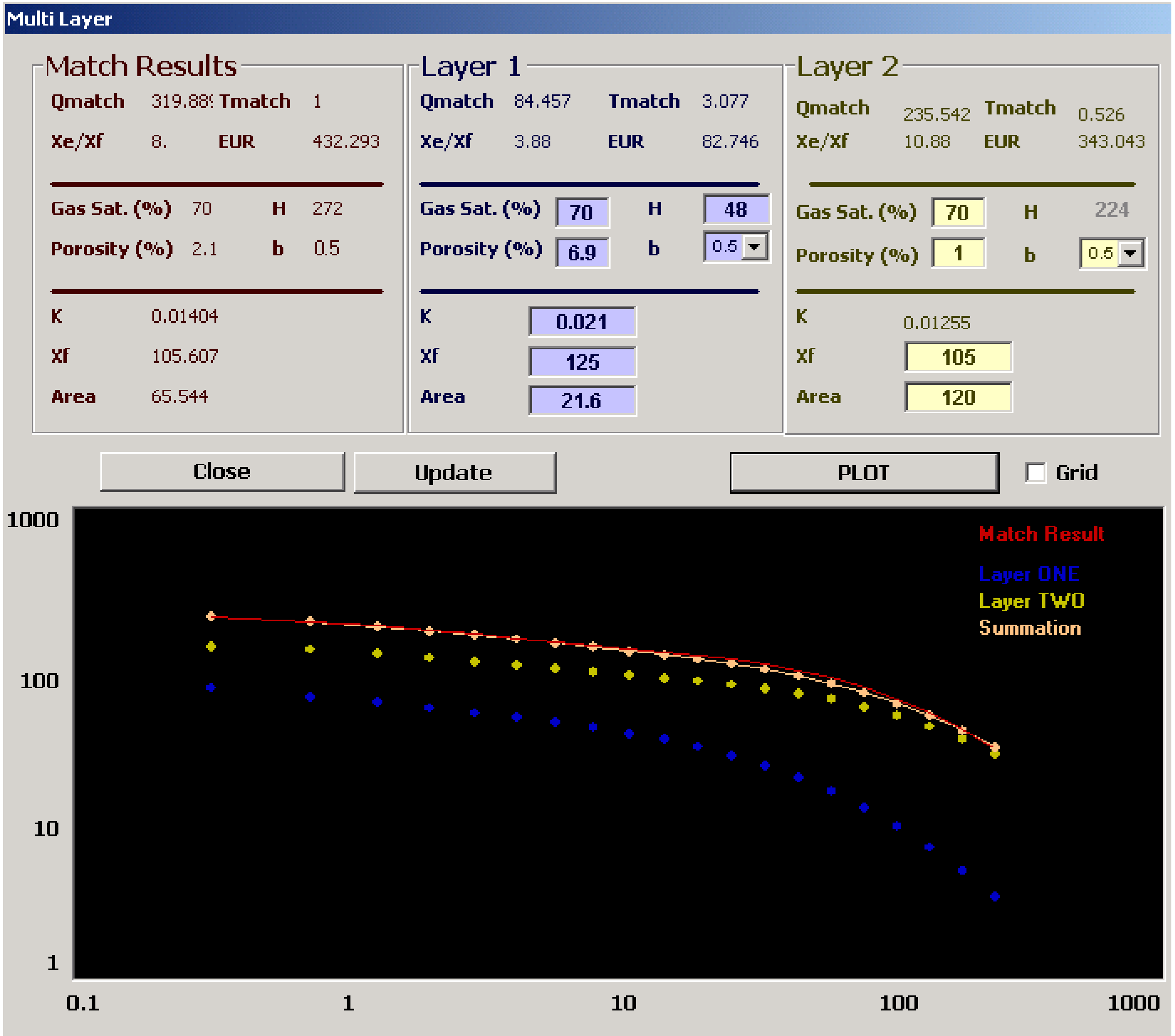

Figure 37 – Area 6 Single Layer Type Curve Match

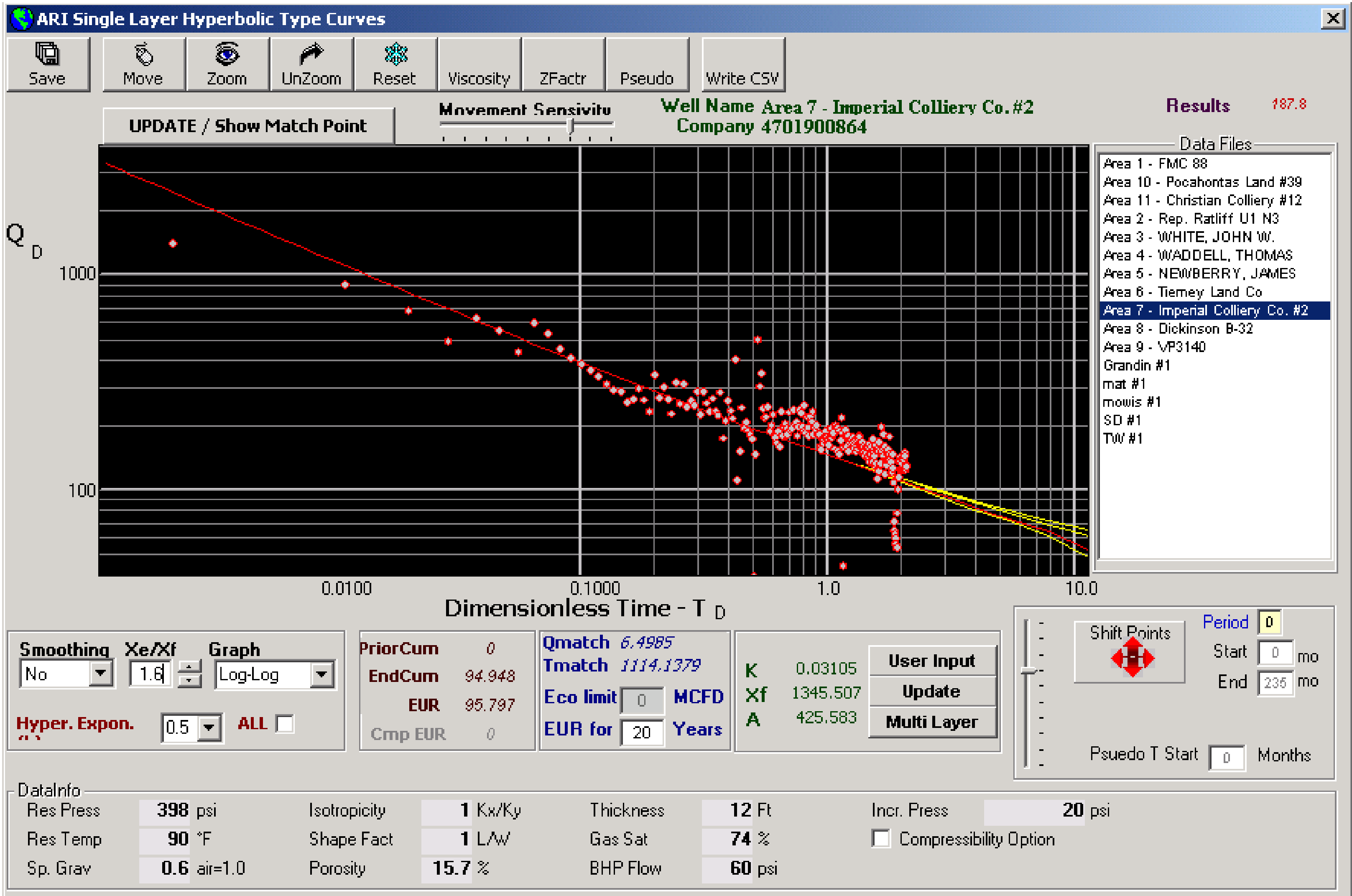

Figure 38 – Area 6 Multiple Layer Type Curve Match Results

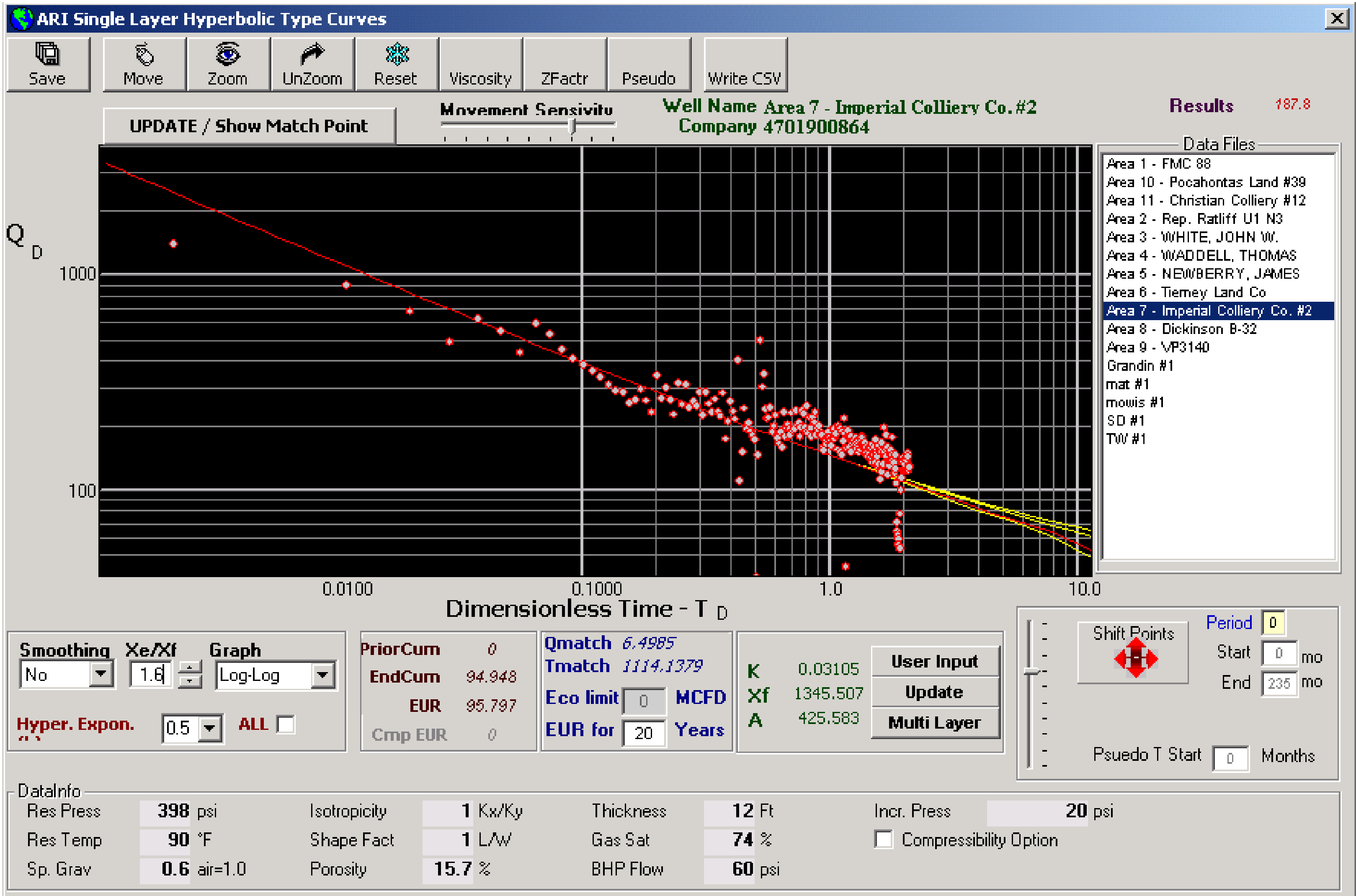

Figure 39 – Area 7 Single Layer Type Curve Match

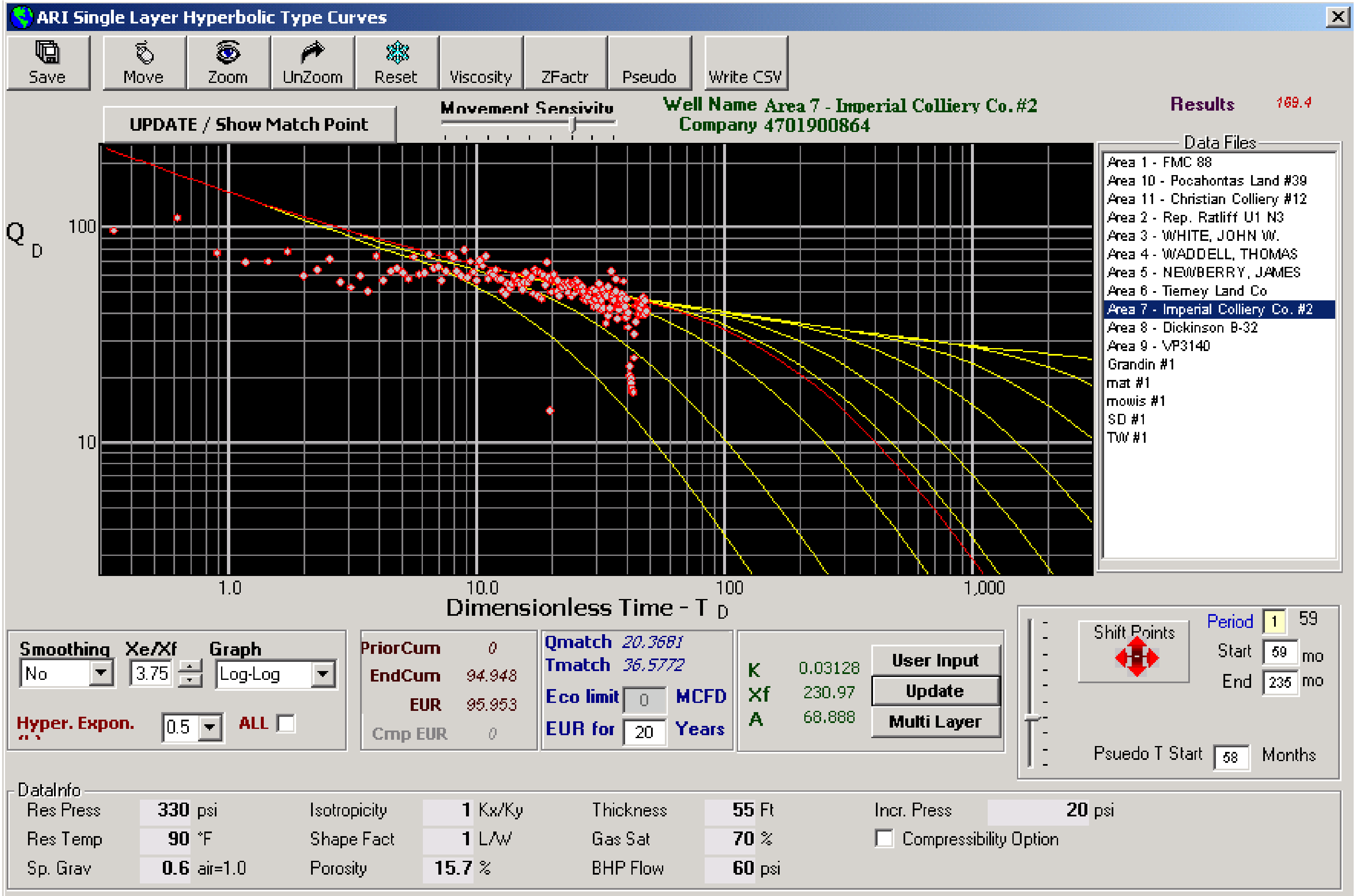

Figure 40 – Area 7 Restart Single Layer Type Curve Match

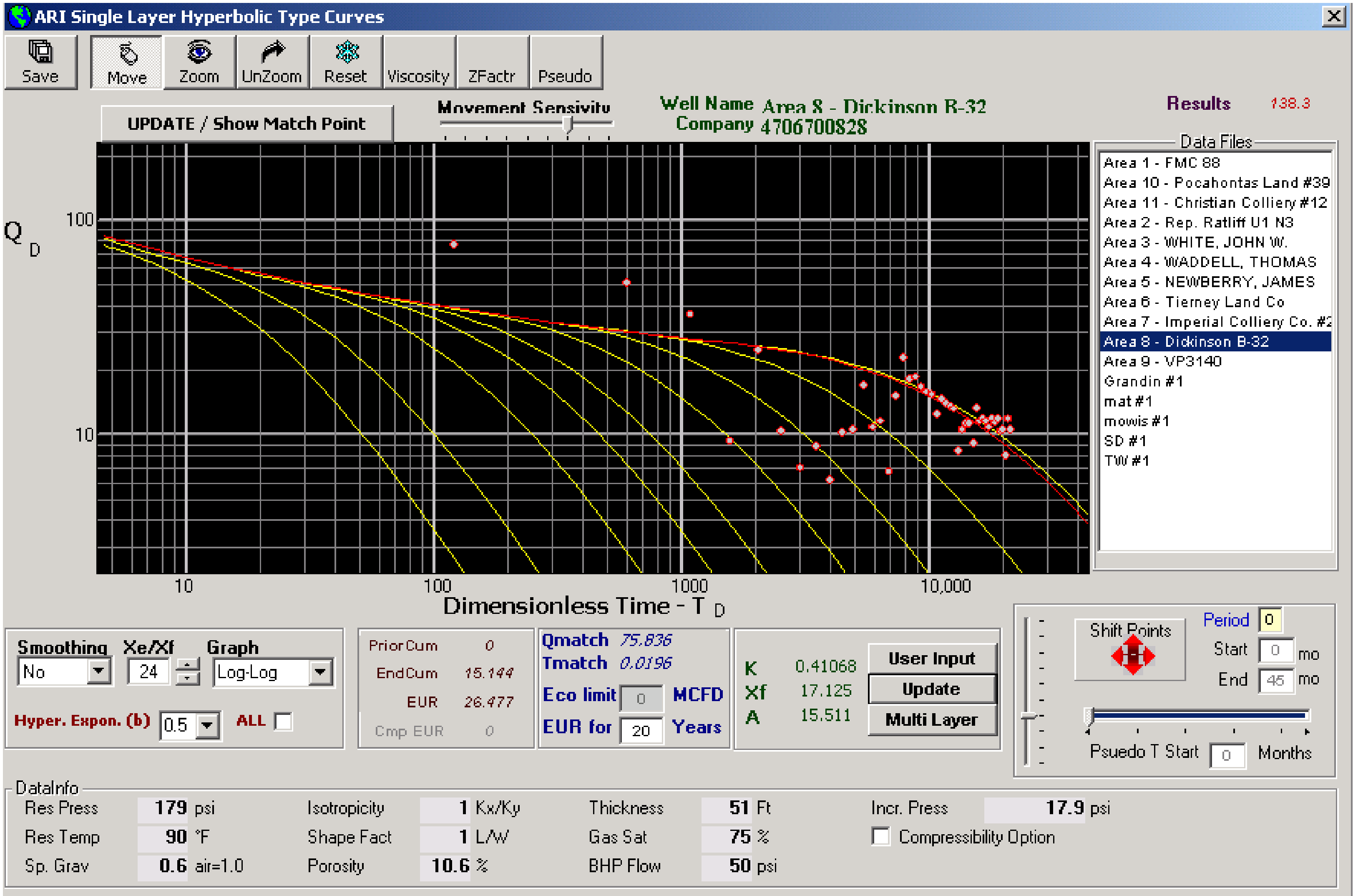

Figure 41 – Area 8 Single Layer Type Curve Match

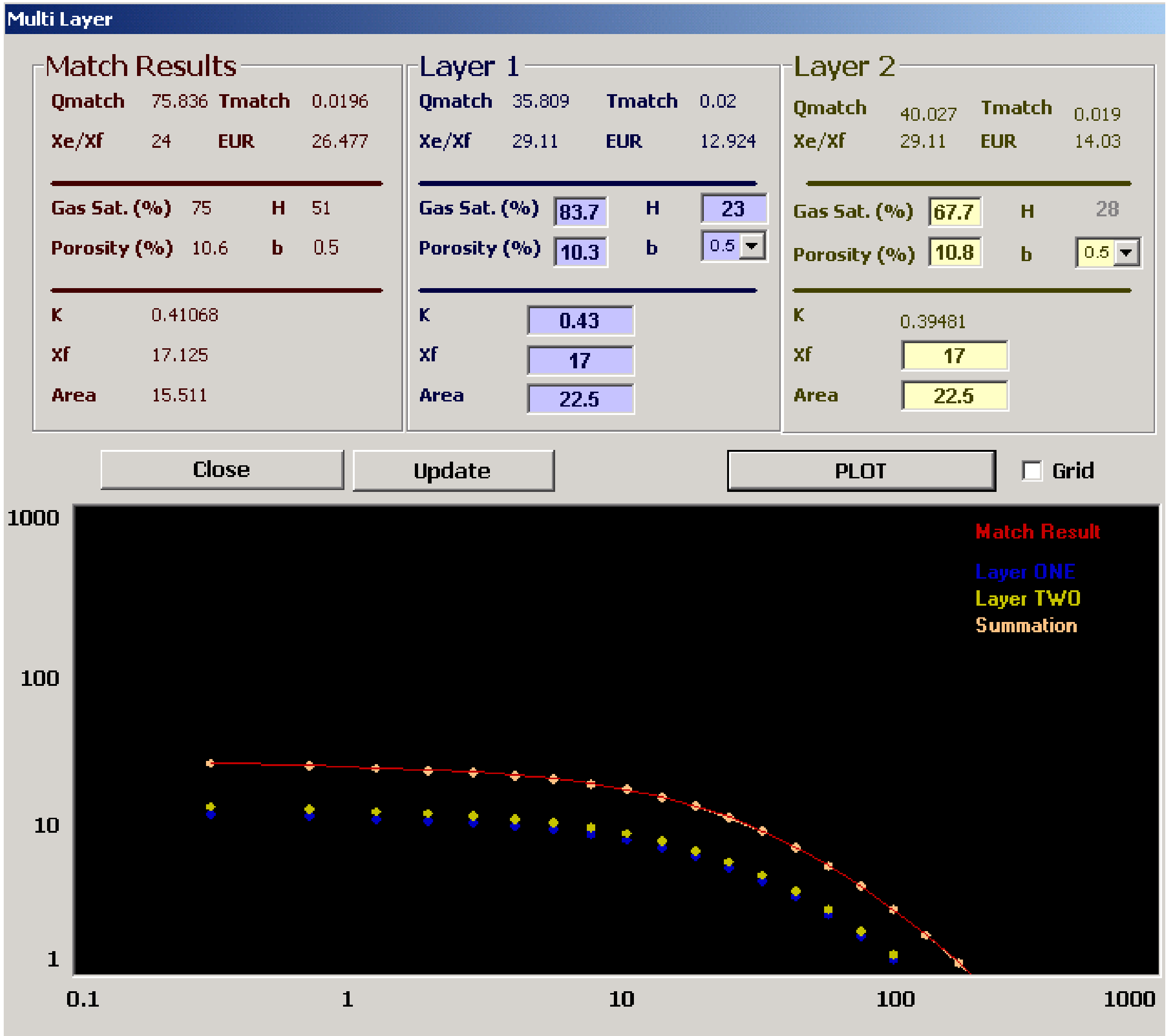

Figure 42 – Area 8 Multiple Layer Type Curve Match Results

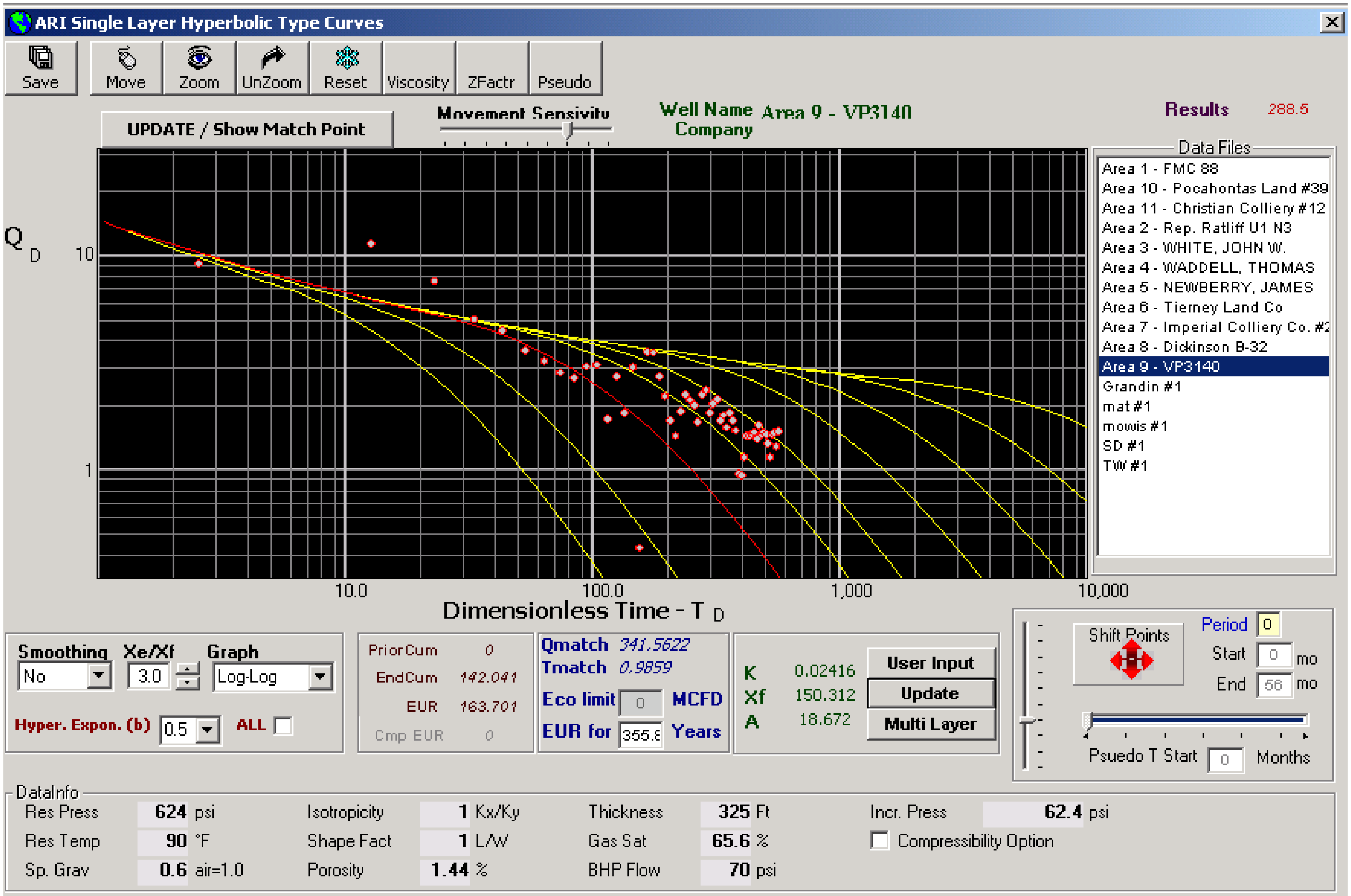

Figure 43 – Area 9 Single Layer Type Curve Match

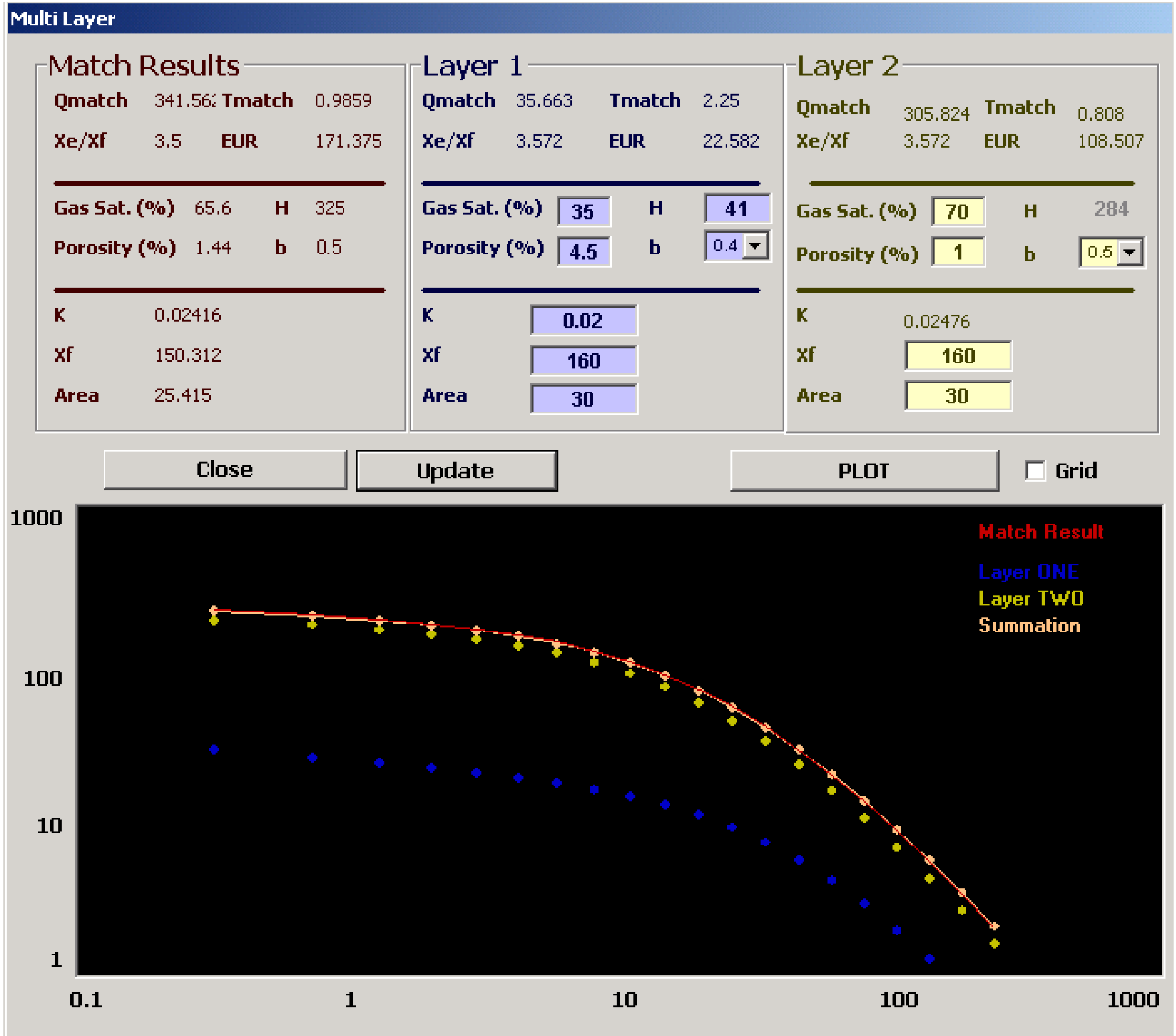

Figure 44 – Area 9 Multiple Layer Type Curve Match Results

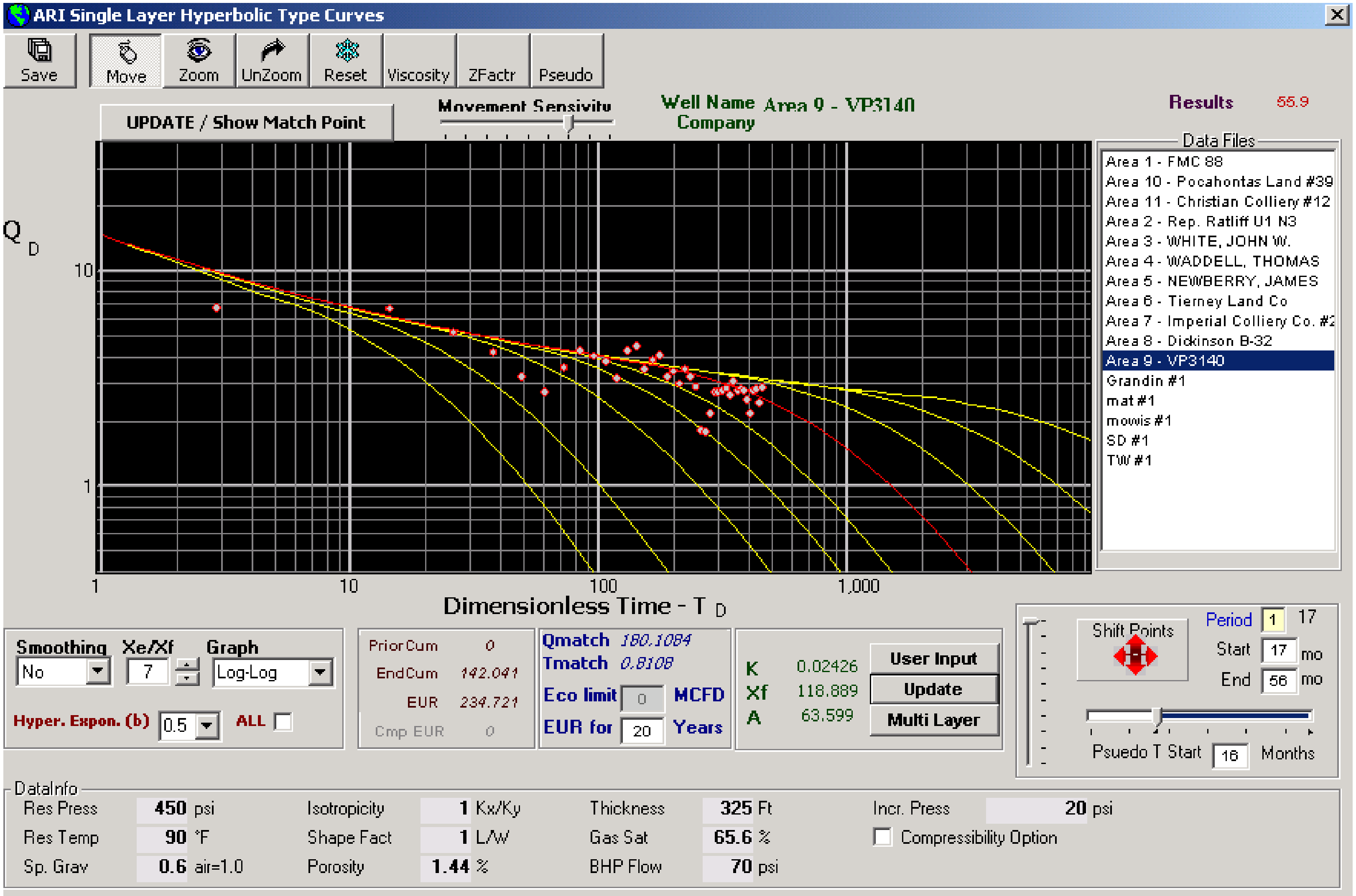

Figure 45 – Area 9 Restart Single Layer Type Curve Match

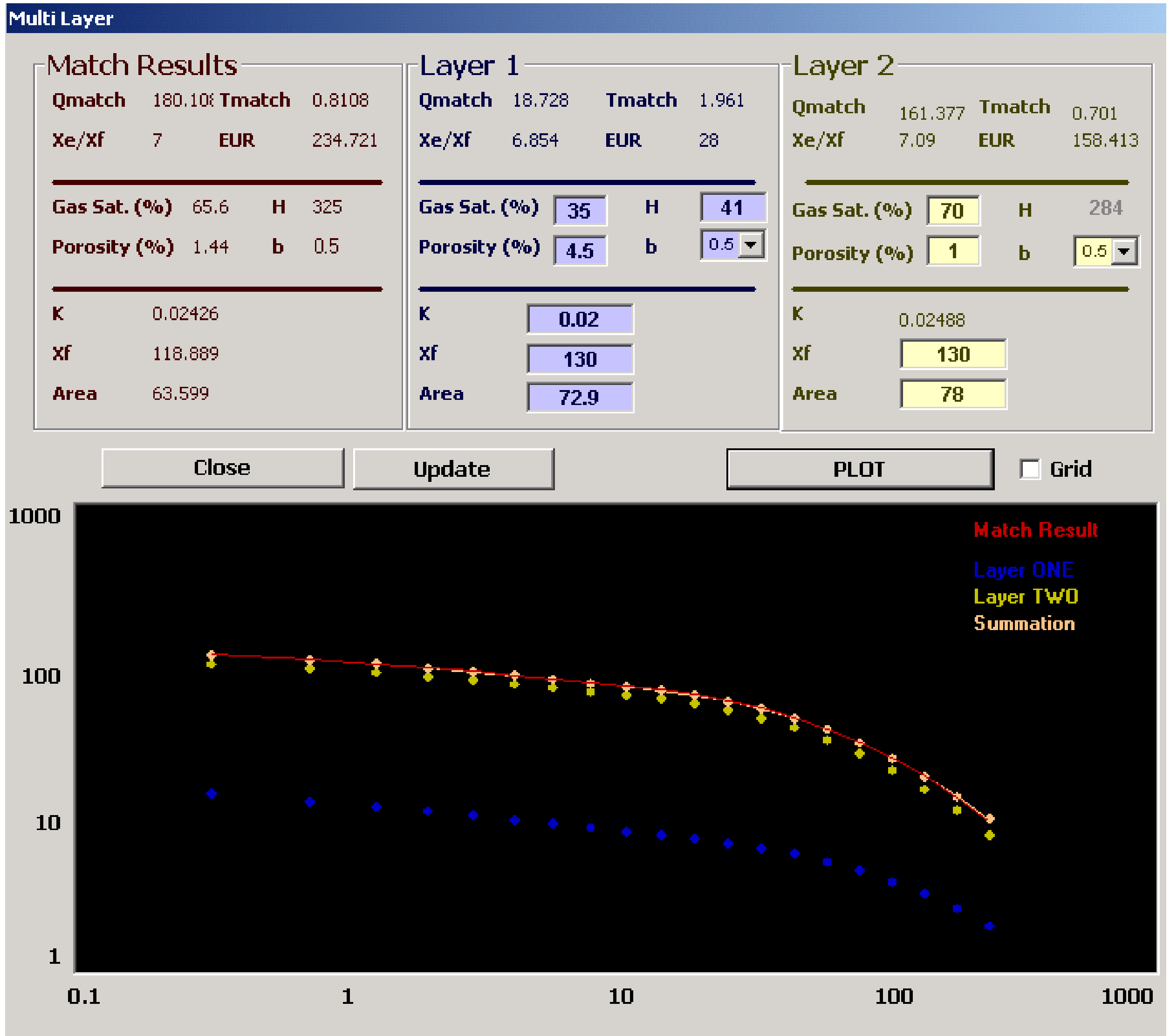

Figure 46 – Area 9 Restart Multiple Layer Type Curve Match Results

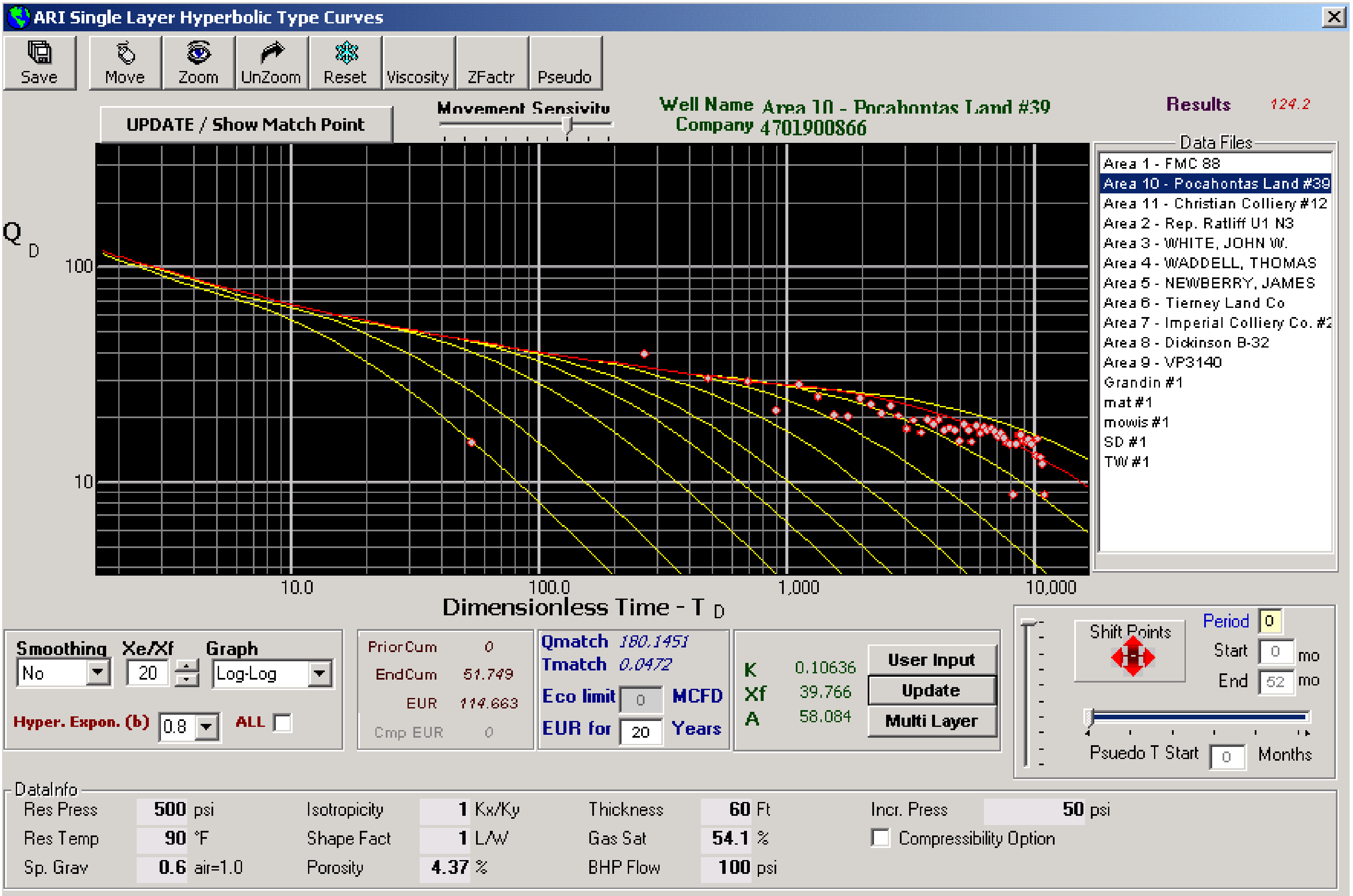

Figure 47 – Area 10 Single Layer Type Curve Match

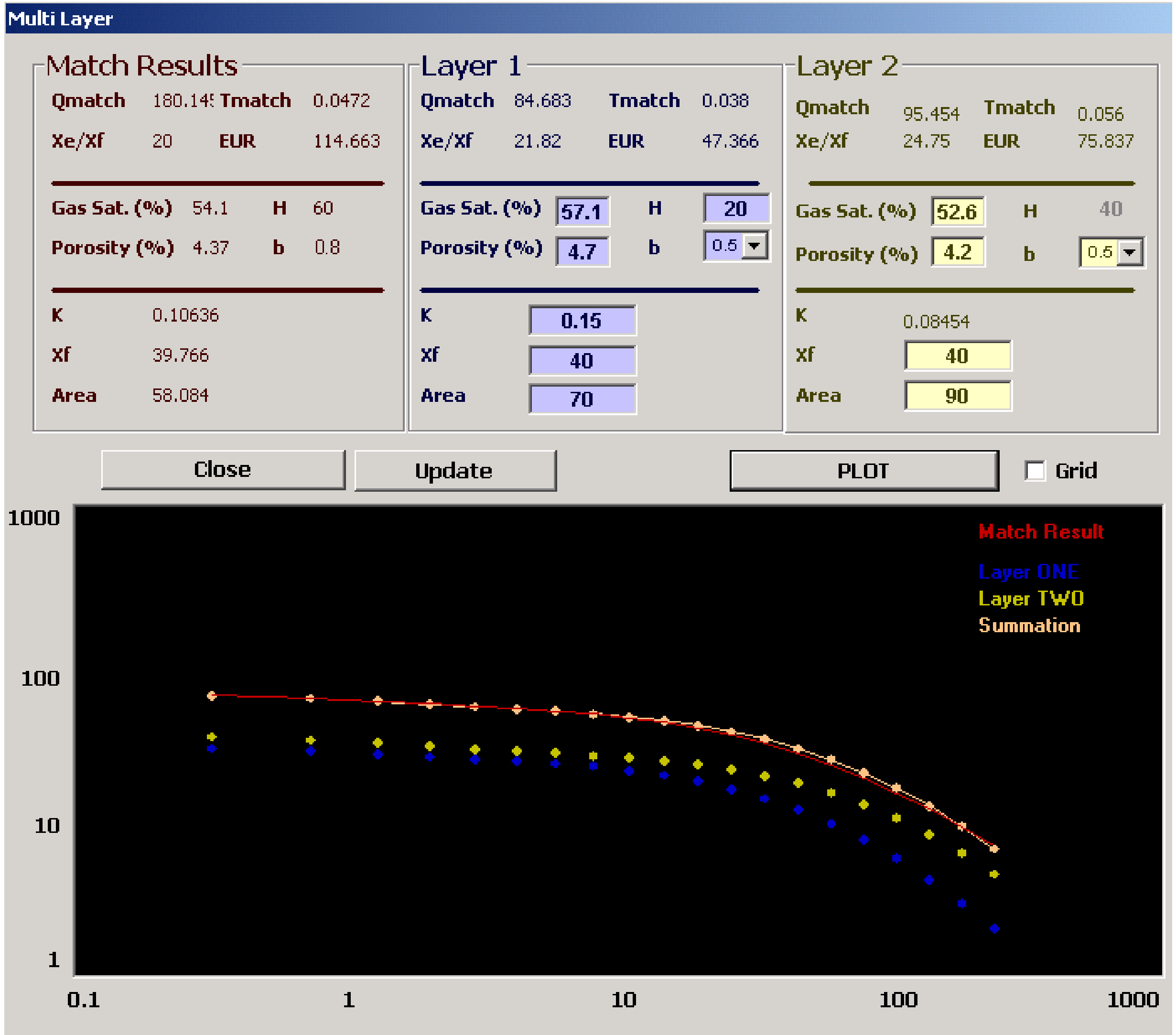

Figure 48 – Area 10 Multiple Layer Type Curve Match Results

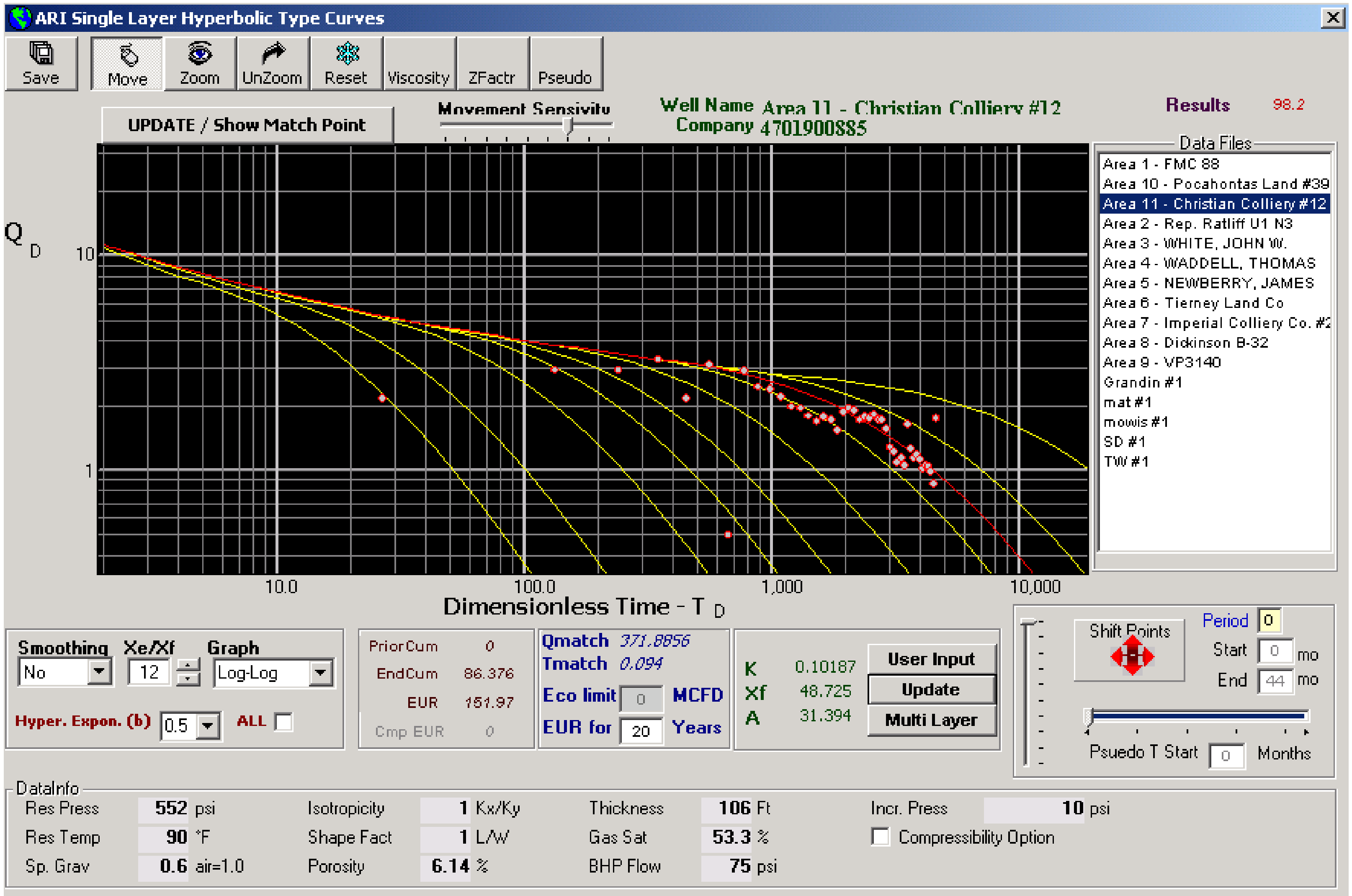

Figure 49 – Area 11 Single Layer Type Curve Match

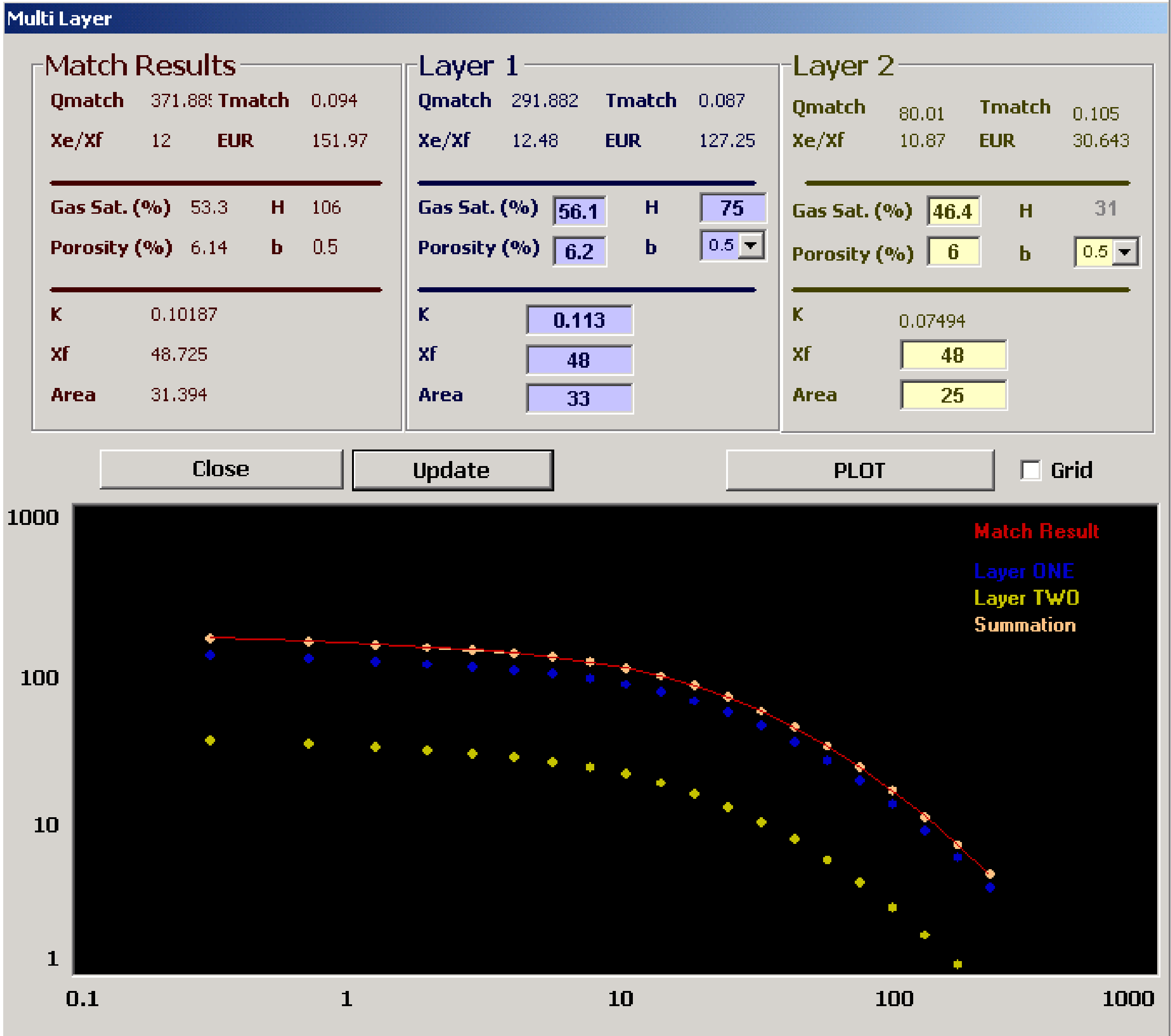

Figure 50 – Area 11 Multiple Layer Type Curve Match Results

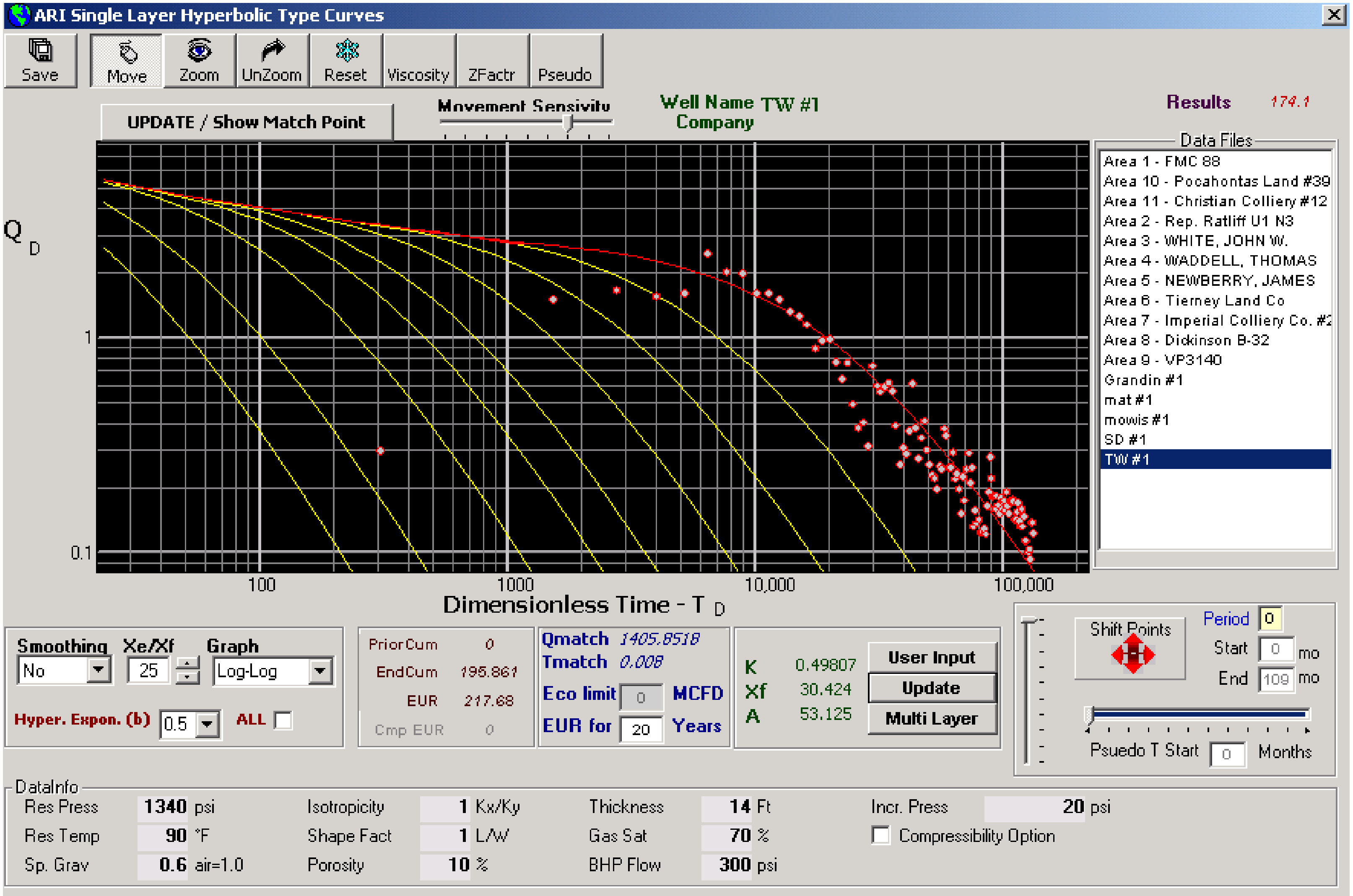

Figure 51 – Area 12 Single Layer Type Curve Match

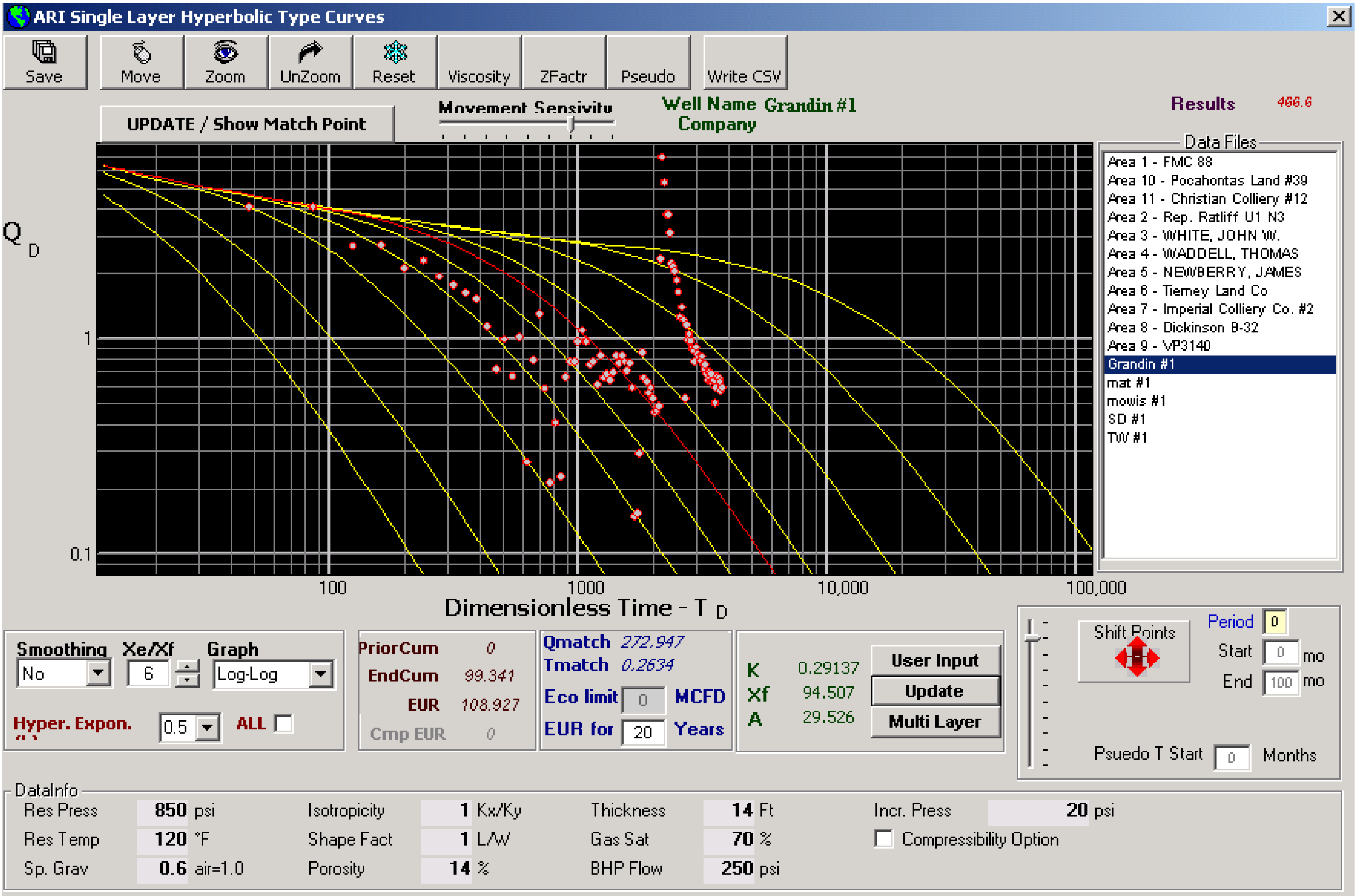

Figure 52 – Area 13 Single Layer Type Curve Match

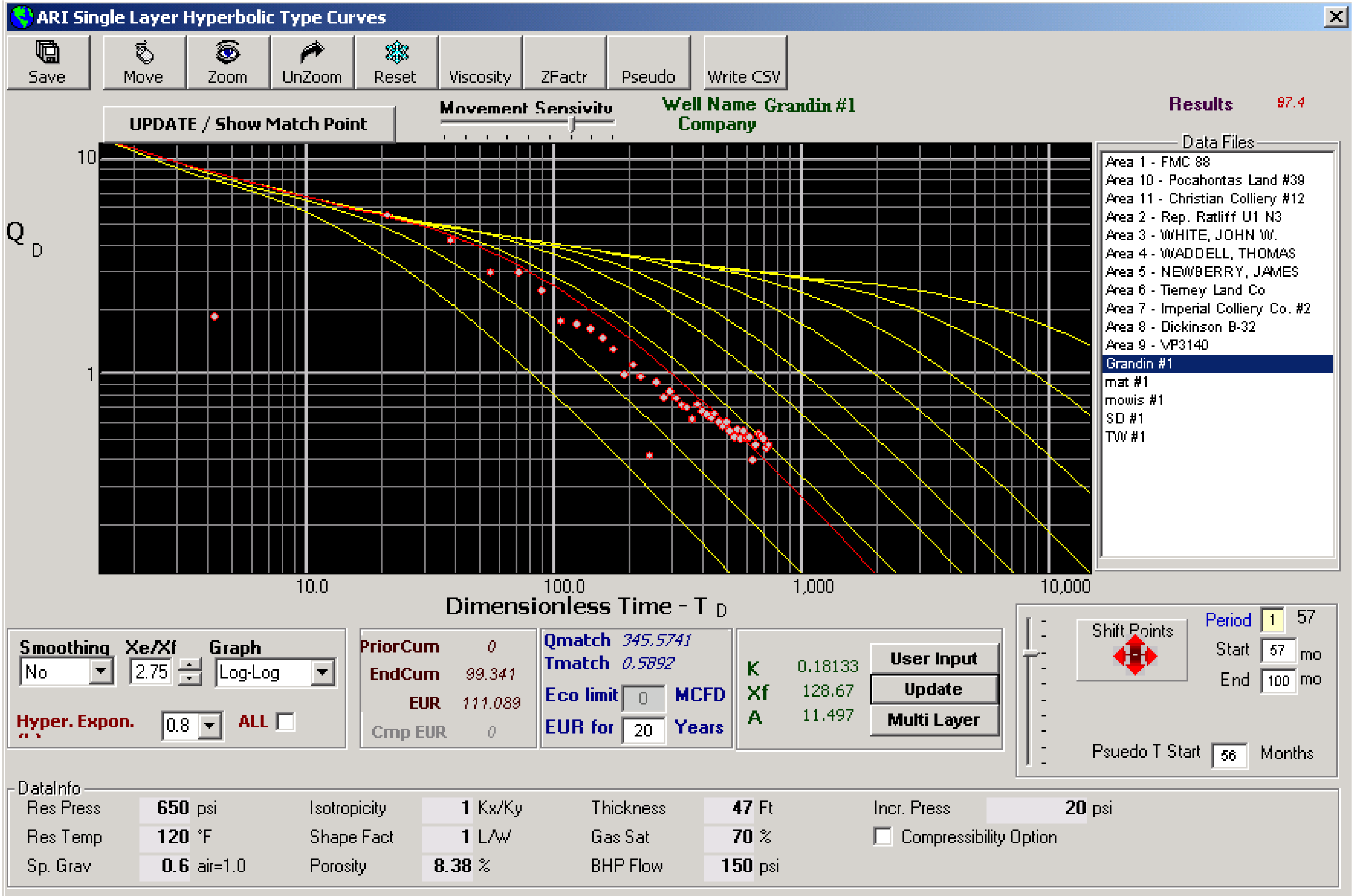

Figure 53 – Area 13 Restart Single Layer Type Curve Match

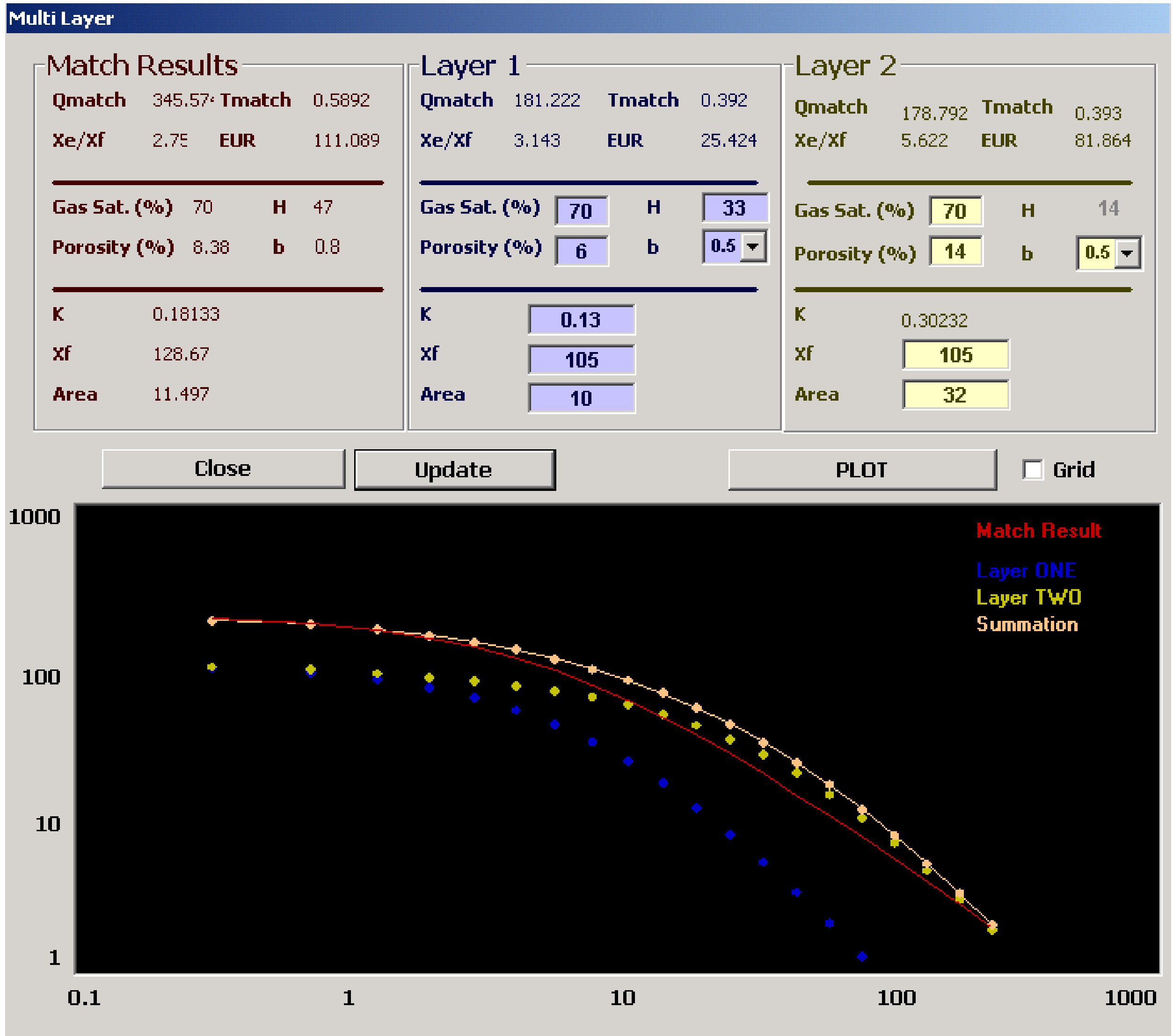

Figure 54 – Area 13 Restart Multiple Layer Type Curve Match Results

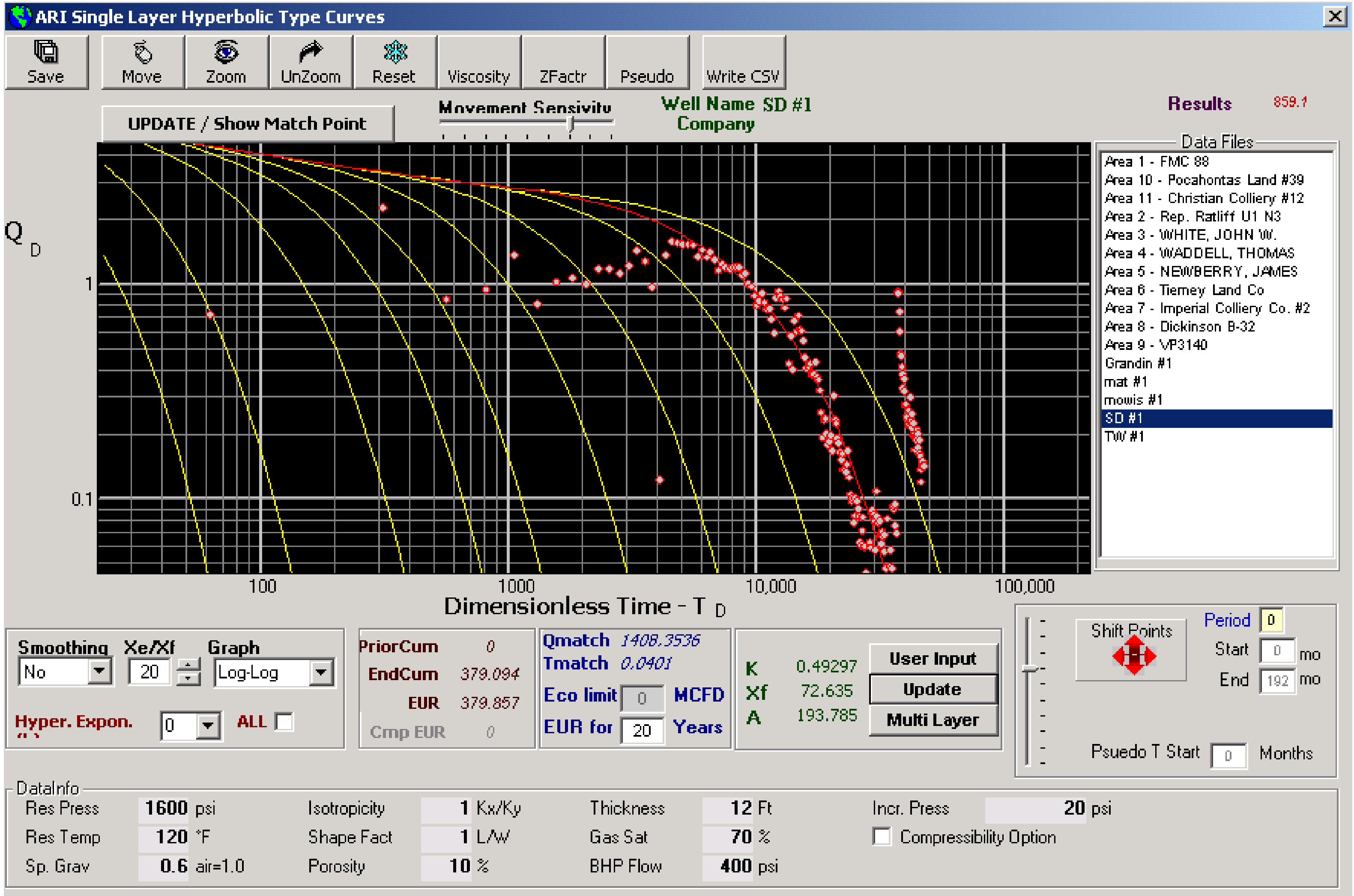

Figure 55 – Area 14 Single Layer Type Curve Match

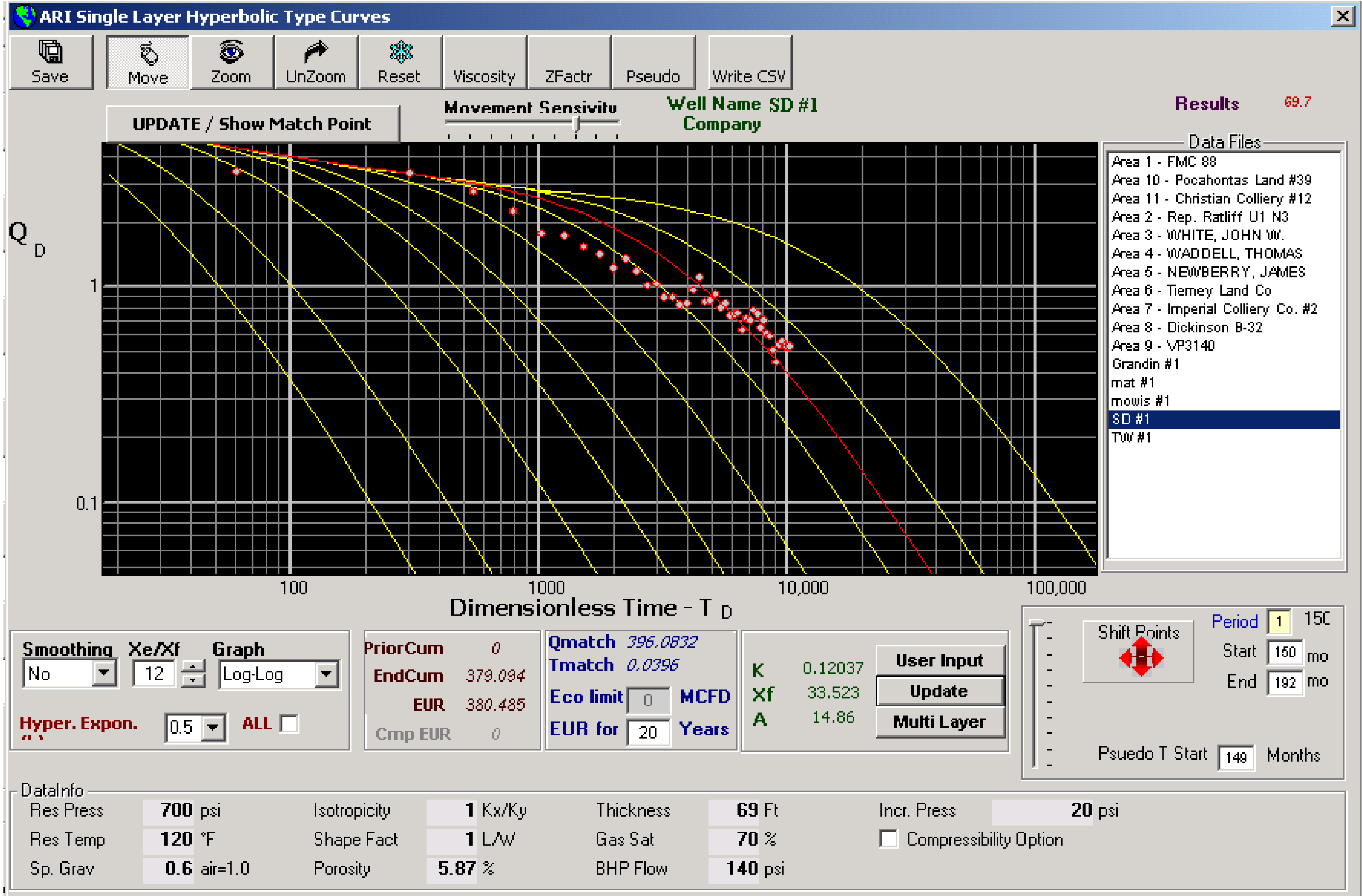

Figure 56 – Area 14 Restart Single Layer Type Curve Match

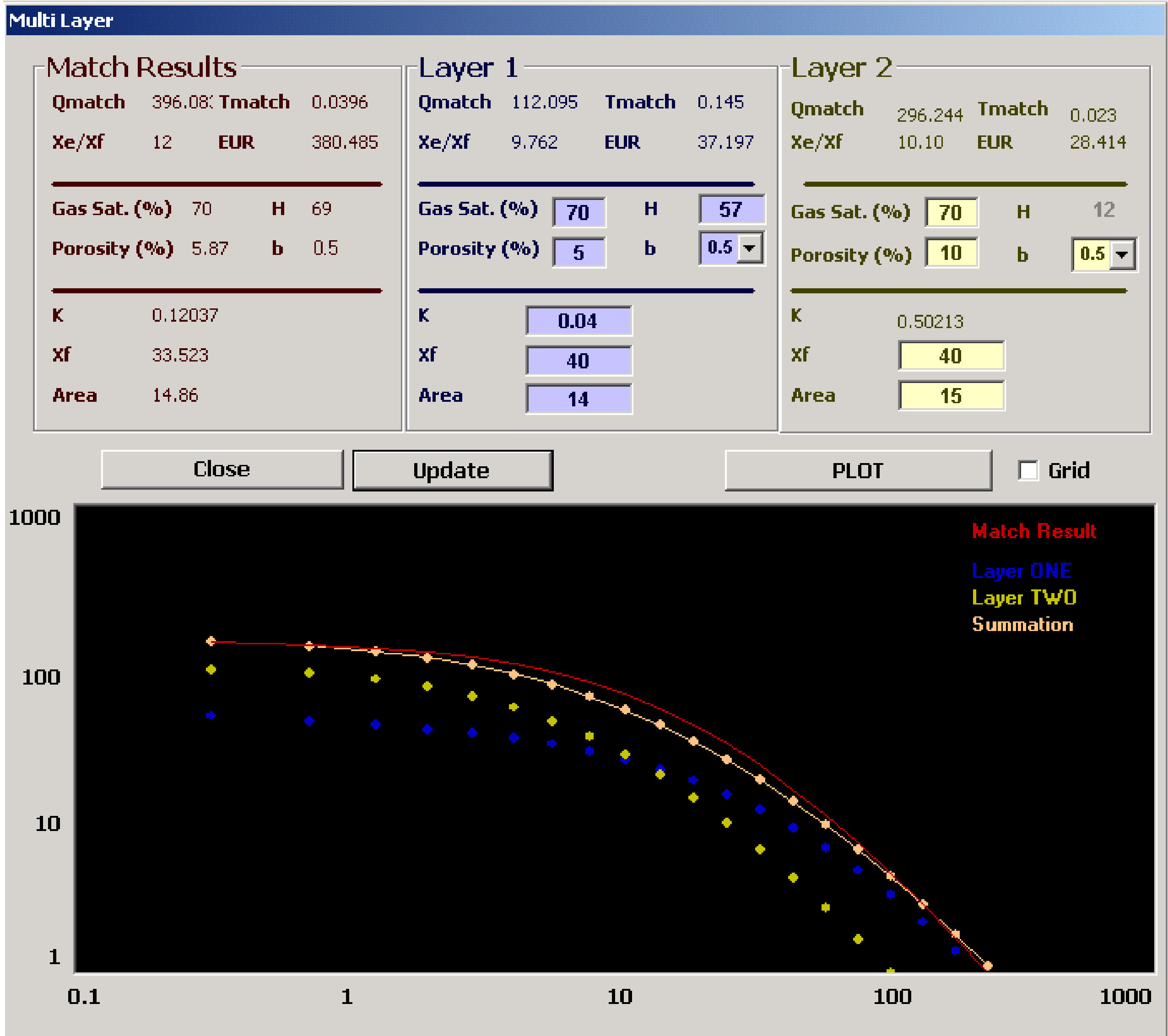

Figure 57 – Area 15 Restart Multiple Layer Type Curve Match Results

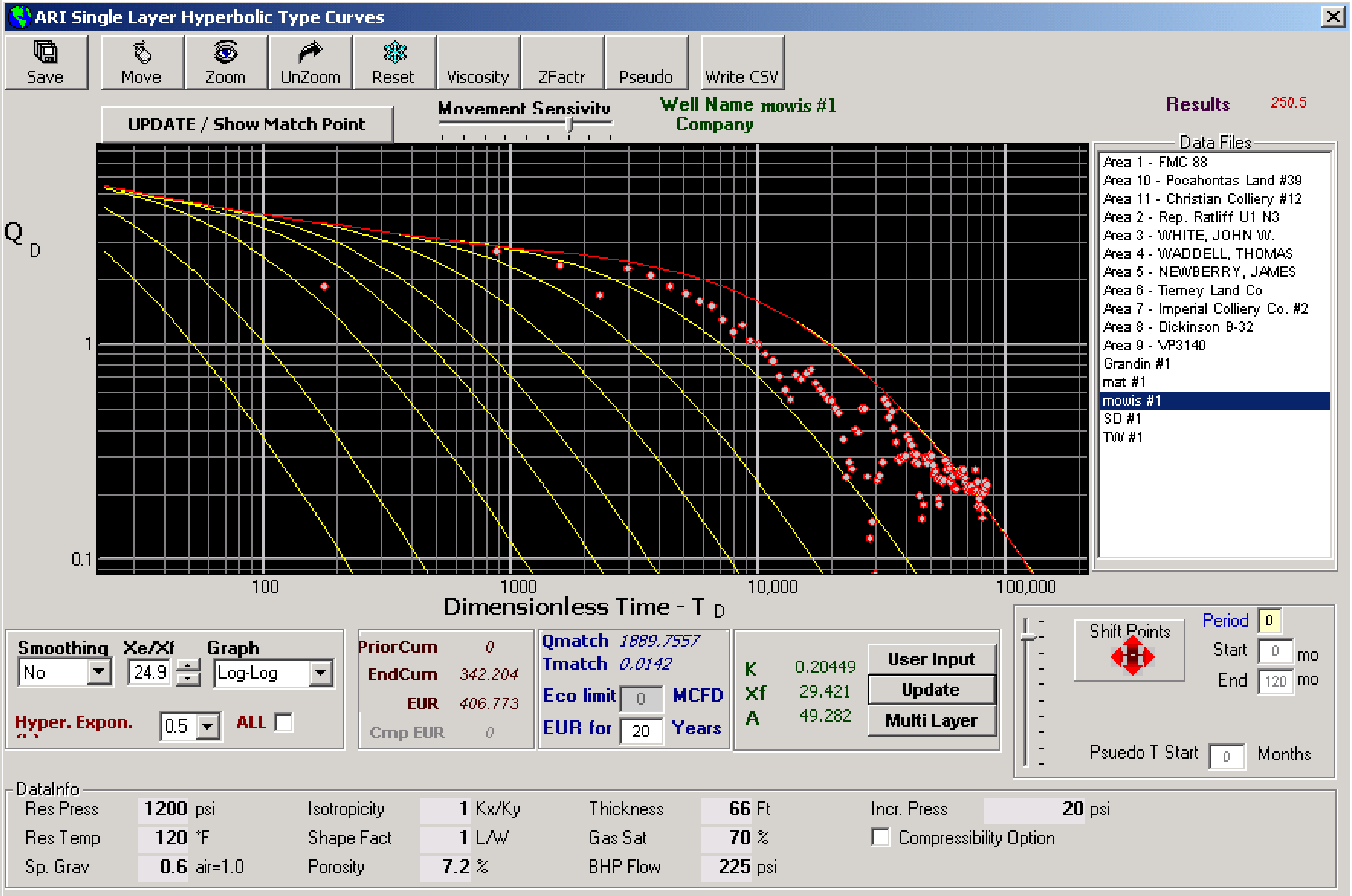

Figure 58 – Area 15 Single Layer Type Curve Match

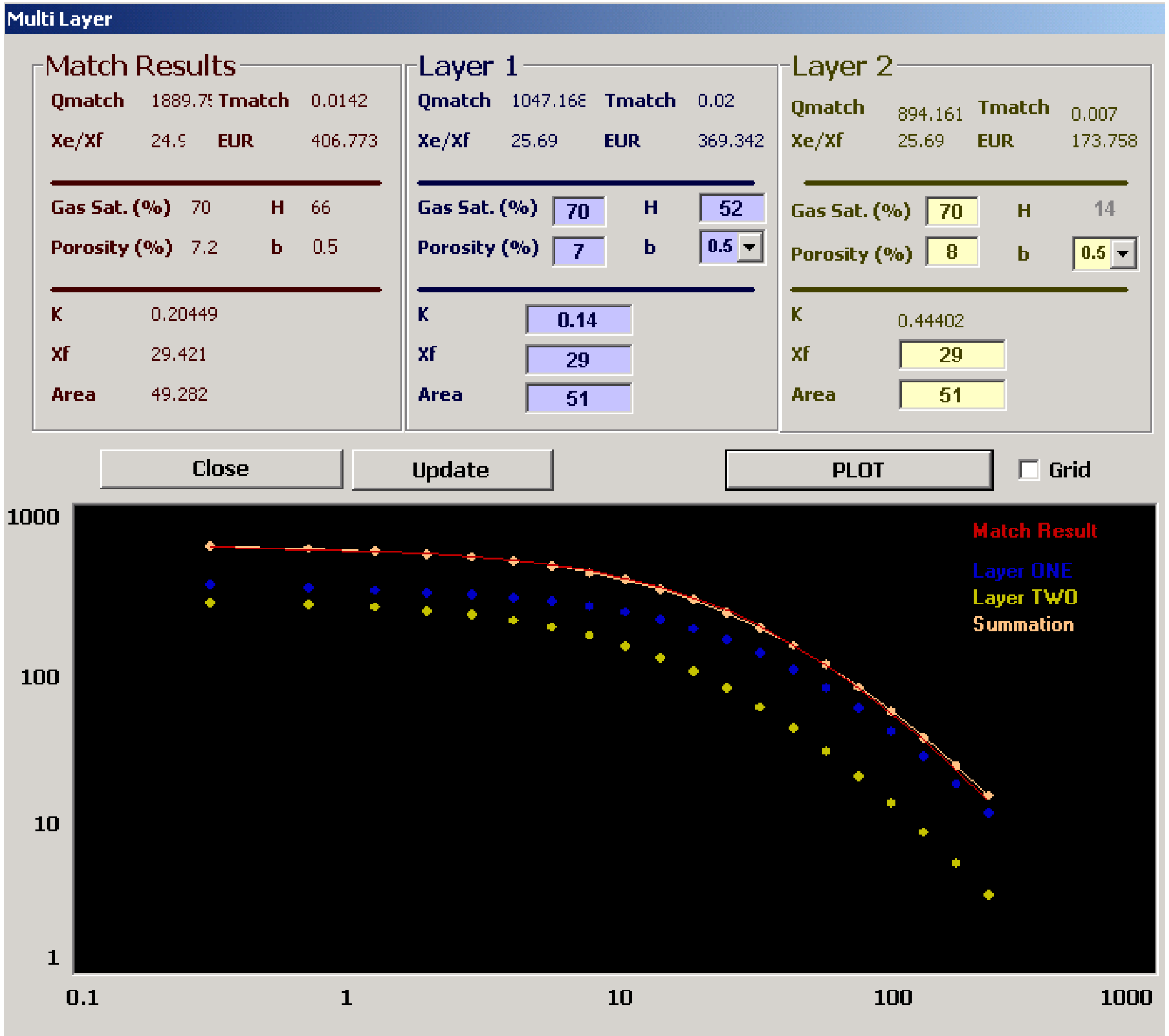

Figure 59 – Area 15 Multiple Layer Type Curve Match Results

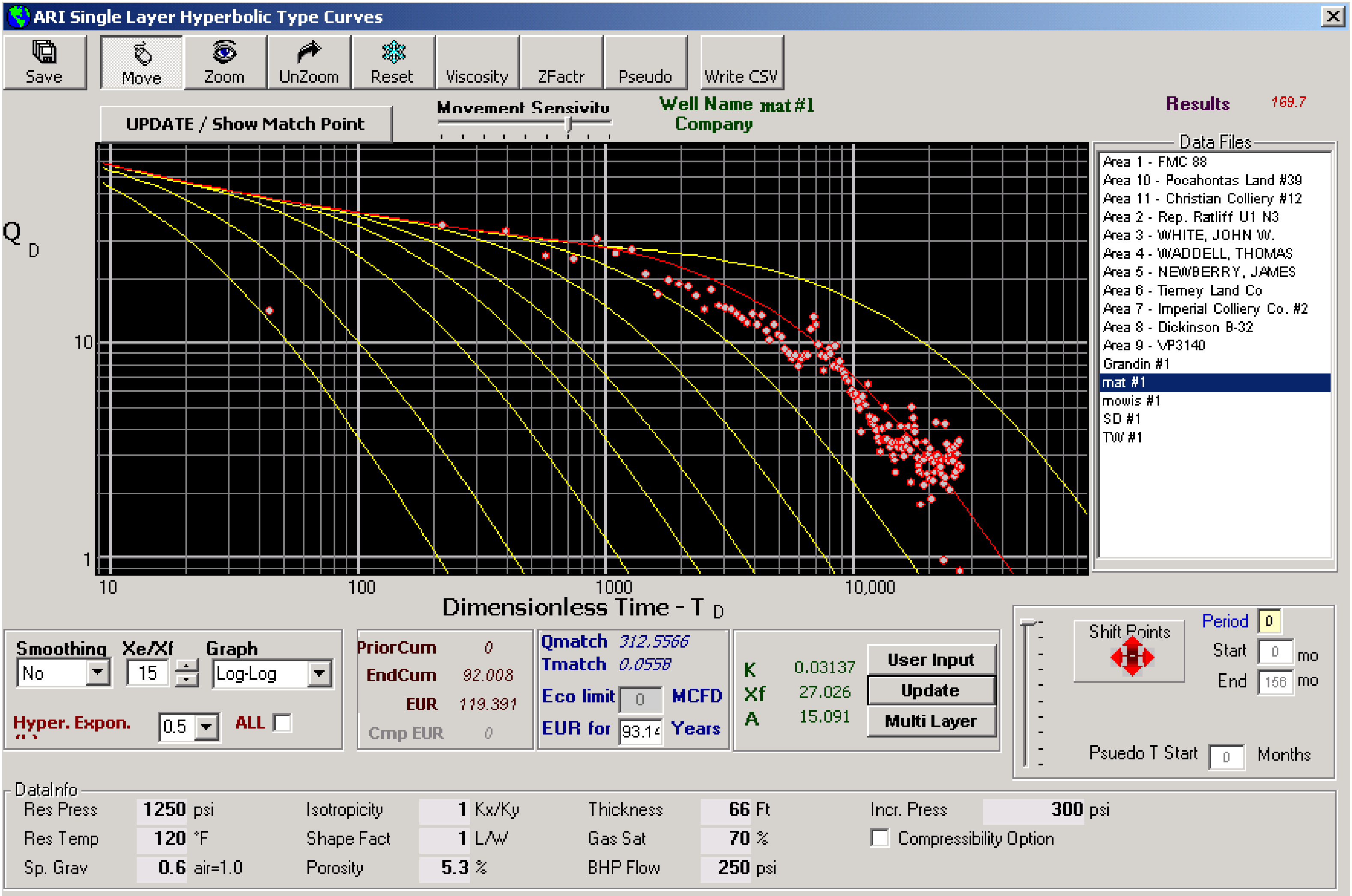

Figure 60 – Area 16 Single Layer Type Curve Match

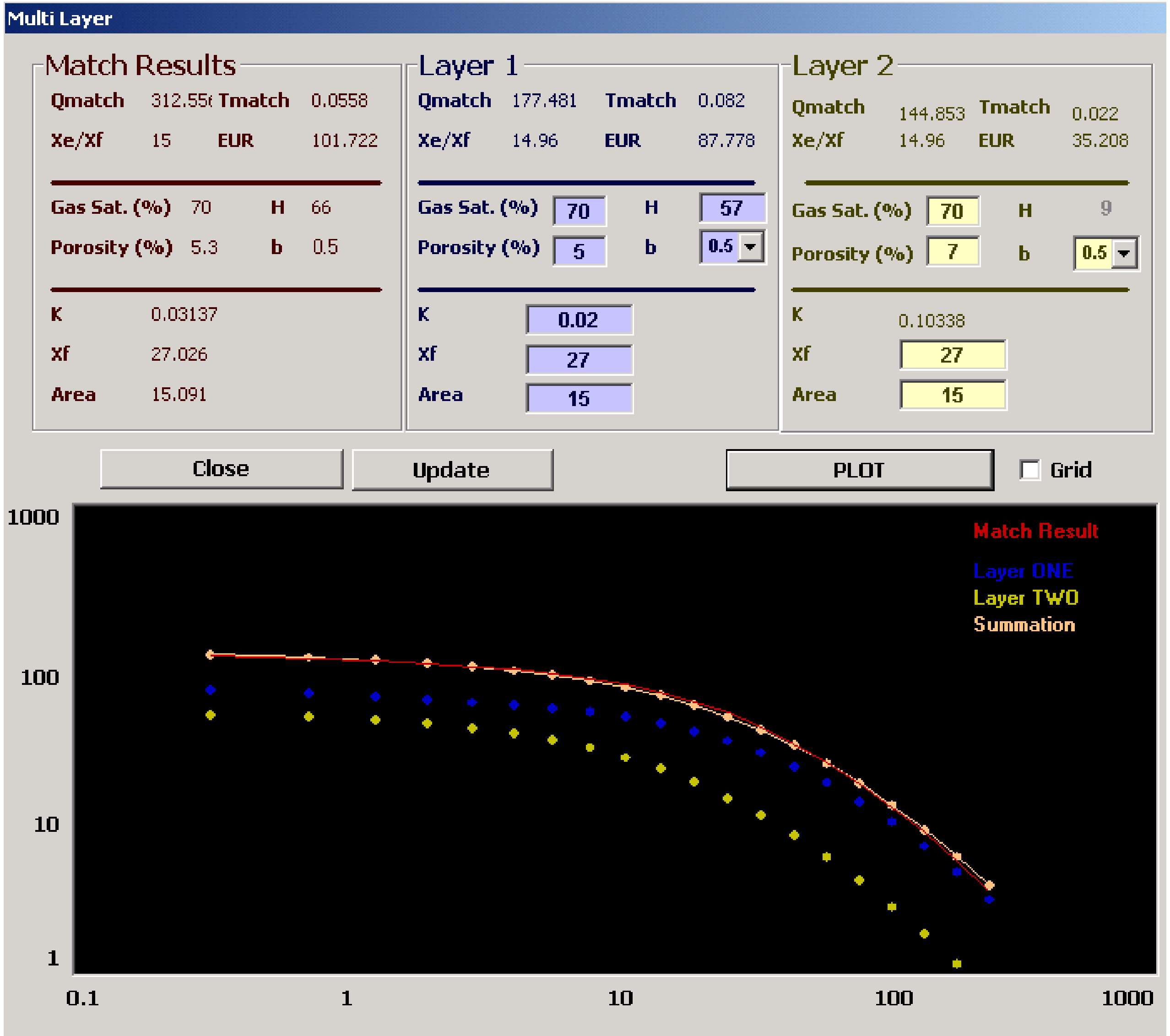

Figure 61 – Area 16 Multiple Layer Type Curve Match Results

Development of Diagnostic Techniques to Identify Bypassed Gas Reserves and Badly Damaged Productive Zones in Gas Stripper Wells in the Rocky Mountain Laramide Basins

during the Period 05/15/2001 to 03/14/2002

By

Ronald C. Surdam
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March 14, 2002

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For
U.S. Department of Energy
National Energy Technology Laboratory
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DISCLAIMER

Overview

Many of the gas stripper wells in the Rocky Mountain Laramide Basins (RMLB) have resulted from a very poor understanding of subsurface fluid-flow systems and their impact on drilling, completion, and stimulation techniques. Without a clear understanding of how these systems affect drilling, gas wells characterized by highly damaged productive zones or considerable bypassed pay are common. It is clear that a process-oriented technology is needed to address the specific problems encountered when drilling in anomalously pressured rock-fluid systems.

The essential problem to be addressed in this work is how to identify bypassed gas and badly damaged productive zones in RMLB gas stripper wells. The development of new diagnostic techniques that will allow such identification of bypassed gas and badly damaged productive zones in these wells is imperative, for if these zones can be identified and remediation/recompletion strategies designed and executed, the life of many gas stripper wells will be extended substantially. The goal of using these techniques will be to effectively and efficiently expedite additional gas production from gas stripper wells.

Work Accomplished

Our study area consists of the Wind River and Greater Green River basins (Figure 1), which together contain 5,537 gas wells, of which we have access to complete log suites and production data for 375 wells. From the 375 wells, 45 test wells were chosen for the proposed work, including commercial gas wells, gas stripper wells, and abandoned gas wells. For each of the 45 wells, the following tasks were completed:

- Determination of the thickness of the underpressured zone beneath the pressure surface boundary from sonic and mud logs, and acqui-

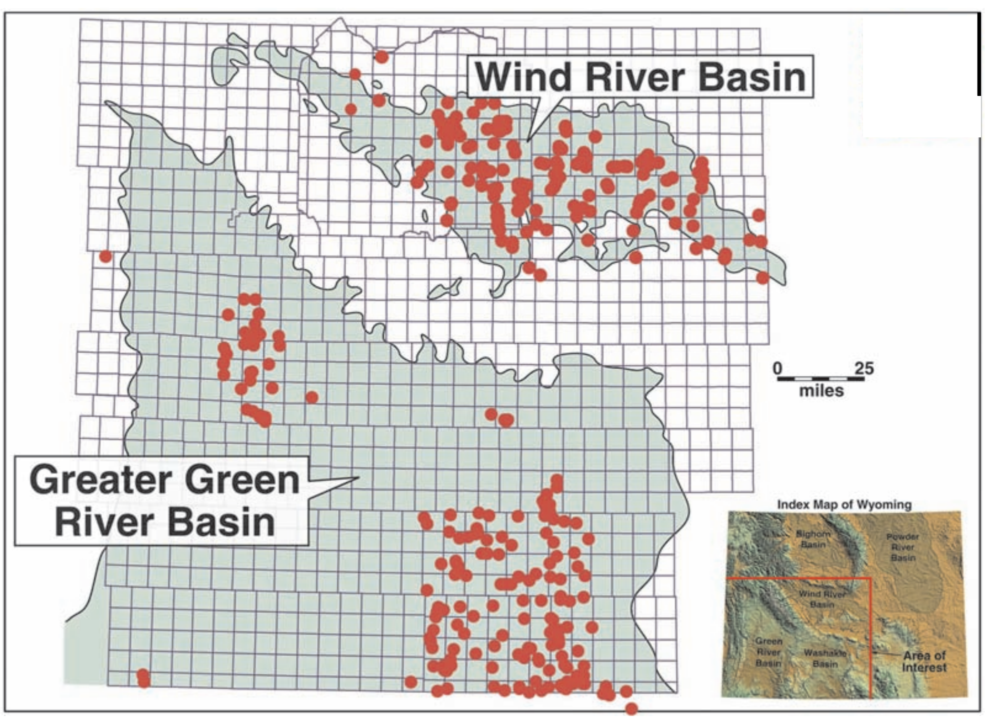

Figure 1. Index map of the study area, the Greater Green River and Wind River basins, WY.

sition of DST and RFT data where available.

- Evaluation of complete log suites for each well, with special emphasis on determining the relationships among the velocity inversion surface (i.e., sonic log), mud log, high resistivity, neutron and density porosity (i.e., gas crossover), gamma ray, and caliper logs.
- Compilation of production data patterns and trends for the 45 wells.
- Evaluation of each well type (stripper, abandoned, gas) using the compiled data:
  - Thickness of underpressured zone
  - Distribution of gas-charged sandstones and fractured shale
  - Production characteristics
  - Distribution of the rock-fluid system that has been exposed to overcompensated mud weight (e.g., potential damage zone)
- Integration of the data and determination of the potential for bypassed gas and damaged productive zones in each of these three types of wells and determination of the most effective, efficient routines for identifying bypassed gas and damaged pay in the gas stripper wells.

Data Collection

In order to create a comprehensive database for this study, 45 wells were chosen from the Greater Green River and Wind River basins (Table 1). Wellhead information was assembled and sonic and mud logs digitized for each of the 45 wells; we are currently analyzing the log data. Gamma ray, neutron porosity, density porosity, resistivity, and caliper logs were acquired and currently are being digitized. Available initial production, production zone, DST, and RFT data also are being acquired.

Determination and Delineation of the Fluid-Flow System

The fluid-flow systems in the RMLB are known to be compartmentalized, both on a regional and local scale. Regionally, these basins are divided into at least three large compartments; locally, these large compartments are subdivided into several smaller compartments (Figure 2). The boundary between the normally pressured, water-saturated fluid system and the underlying anomalously pressured, gas-charged fluid system is characterized by a significant sonic/seismic velocity inversion, which corresponds to the regional pressure surface boundary. Below this boundary, the velocity can be up to 2200 m/s slower than that predicted by the normal regional velocity/depth gradient. The regional pressure surface boundary is especially important because in the RMLB, a huge portion of the cumulative gas production, including most gas stripper wells, is from reservoirs spatially located below, but within 2000 feet of the boundary.

Sonic logs from 45 wells (Table 1), combined with DST, RFT, and mud data, were used to determine the fluid-flow regime (i.e., the pressure surface boundary and the underpressured zone below this boundary). Anomalous velocity profiles were generated for all 45 wells (Figures 3 through 5). The anomalous velocity was calculated by systematically removing the regional velocity-depth gradient from the sonic velocity profiles. Rocks with normal velocity are characterized by normal pressure and a water-dominated, single-phase fluid-flow system, whereas rocks with anomalous velocity are characterized by anomalous pressure (overpressure or underpressure) and a multiphase fluid-flow system (Surdam et al., 1997).

These anomalous velocity profiles are used to determine the: (1) pressure surface boundary, (2) interval with anomalous pressure, and (3) gas-charged, anomalously pressured section

Table 1. List of wells using in this project.

Greater Green River Basin

Well Name	API #	Township	Range	Section	Status
Canyon Creek Unit 32	4903722827	T12N	101W	9	SI
Cherokee Ridge Federal 1	4903720518	T12N	R96W	15	A
New Moon Unit 1	4903722317	T13N	R95W	13	SI
Federal 3-5	4903722029	T14N	R100W	5	A
CEPO Lewis 21-18	4903724185	T14N	R95W	18	Gas
Windmill Draw Unit 1	4903721071	T15N	R94W	14	SI
Lario Federal 33-14	4903724076	T15N	R94W	15	SI
Mull Federal 44-18	4903724124	T15N	R94W	18	Gas
Wester Federal 33-6	4903724352	T15N	R94W	6	Gas
Mulligan Draw Unit 6	4903722912	T15N	R95W	25	Gas
Coal Gulch Unit H 1	4900720662	T17N	R93W	2	Gas
Champlin 256	4903720763	T17N	R96W	3	A
C. G. Road Unit 26-3	4903723919	T21N	R94W	26	Gas
Beaver mesa 1-7	4903720416	T24N	R102W	7	A
Federal 21-1	4903722021	T24N	R103W	21	Gas
Freighter Gap Unit 1	4903721904	T24N	R12W	13	SI
Freighter Gap Unit 2	4903721982	T24N	R12W	12	A
Federal 1-1	4903722261	T24N	R14W	1	A
Packsaddle Unit 1	4903721425	T25N	R103W	24	A
Federal Q 1	4903721096	T25N	R96W	28	Gas
Musketeer Unit 1	4903721966	T26N	R101W	8	A
Golden Rod Unit 1	4903520601	T27N	R109W	30	A
Wardell Federal 1	4903520342	T28N	R108W	9	SI
Tot Unit 31-22	4903521652	T28N	R109W	22	Gas
Yellow Point Federal 11-13	4903521887	T28N	R109W	13	Gas
Stud Horse Butte 13-27	4903521359	T29N	R108W	27	Gas
Stud Horse Butte 5-26	4903521374	T29N	R108W	26	Gas
Wagon Wheele 1	4903520124	T30N	R108W	5	SI
West Pinedale 1	4903520348	T30N	R109W	33	SI

Wind River Basin

Shoshone Arapahole Tribal 534	4901320612	T1S	R2E	2	SI
Ocean Lake Tribal	4901321430	T2N	R4E	8	SI
Tribal 24-11	4901320748	T3N	R3E	11	A
Ocean Lake Tribal 1-15	4901321312	T3N	R3E	15	Gas
Tribal MR 30-13	4901321772	T4N	R3E	30	Gas
Tribal Chevron 30-11	4901320725	T4N	R3E	30	Gas
Tribal Sand Mesa 2	4901320800	T4N	R4E	24	Gas
Coastal Owl Creek 1	4901321077	T5N	R3E	26	SI
Ryan Hill Unit 1	4902520002	T32N	R84W	35	A
HSR Steele 16-31	4903521725	T34N	R109W	31	SI
Twidale 1	4902521344	T34N	R87W	15	Oil
Federal USA 17-1	4901320961	T34N	R94W	17	Oil
Wild Hourse Butte 1-16	4902522015	T35N	R88W	16	A
Nawking Draw Unit 2	4901320488	T35N	R90W	25	A
Horseshoe Creek Federal 1	4901321546	T35N	R92W	26	Si
Fuller Reservoir Unit 2	4901320565	T36N	R94W	25	SI

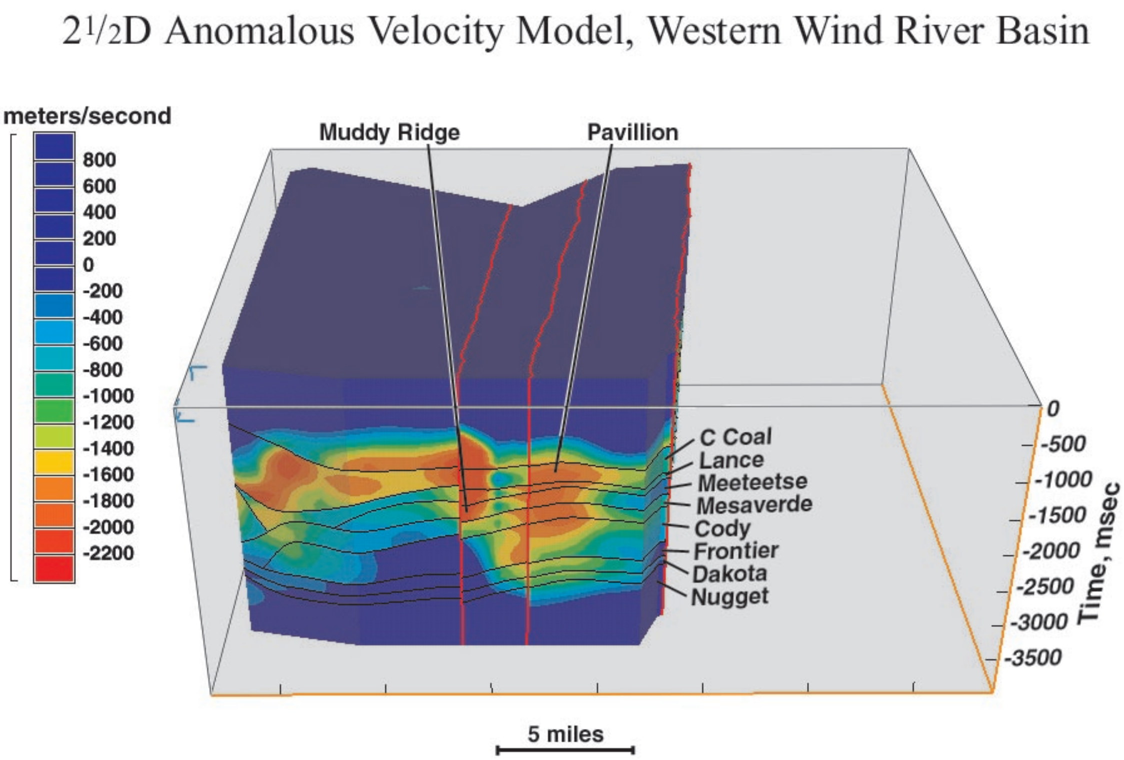

Figure 2. An east-west cross section cut through a 2 ½ D anomalous velocity model showing pressure compartmentalization in the Western Wind River Basin, Wyoming. Red and yellow areas indicate an anomalously pressured and gas-charged rock/fluid system.

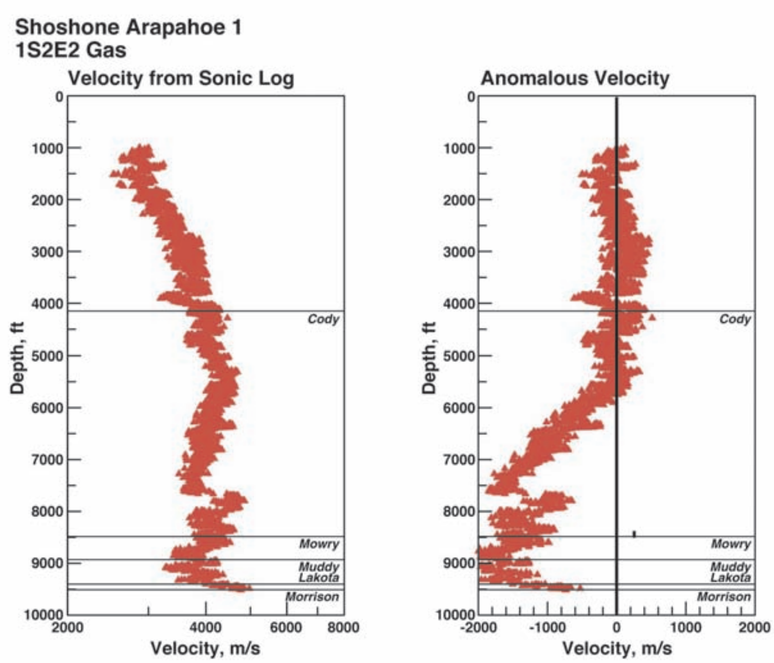

Figure 3. Sonic velocity and anomalous velocity profiles for the well Shoshone Arapahoe 1 well, Wind River Basin, WY. The pressure surface boundary is at 5700 ft.

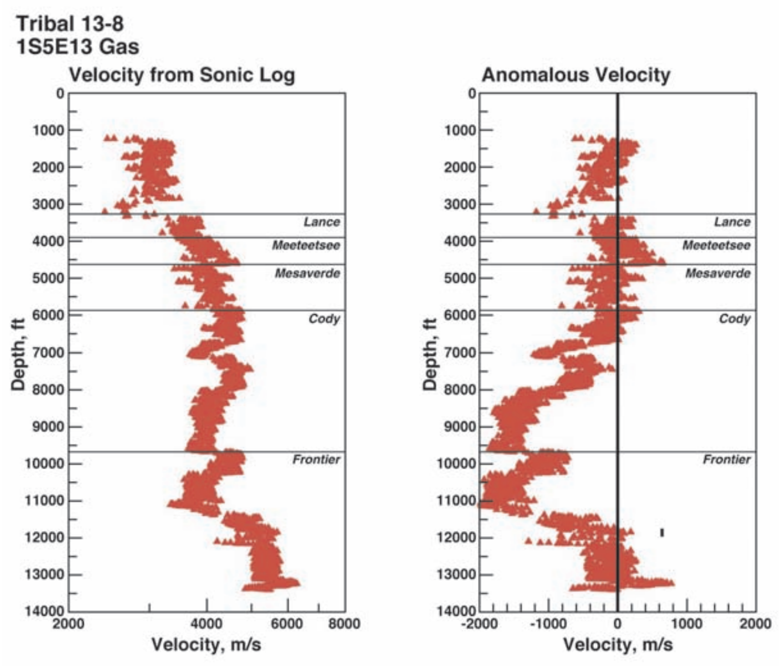

Figure 4. Sonic velocity and anomalous velocity profiles for the Tribal 13-8 well. The pressure surface boundary is at 6600 ft.

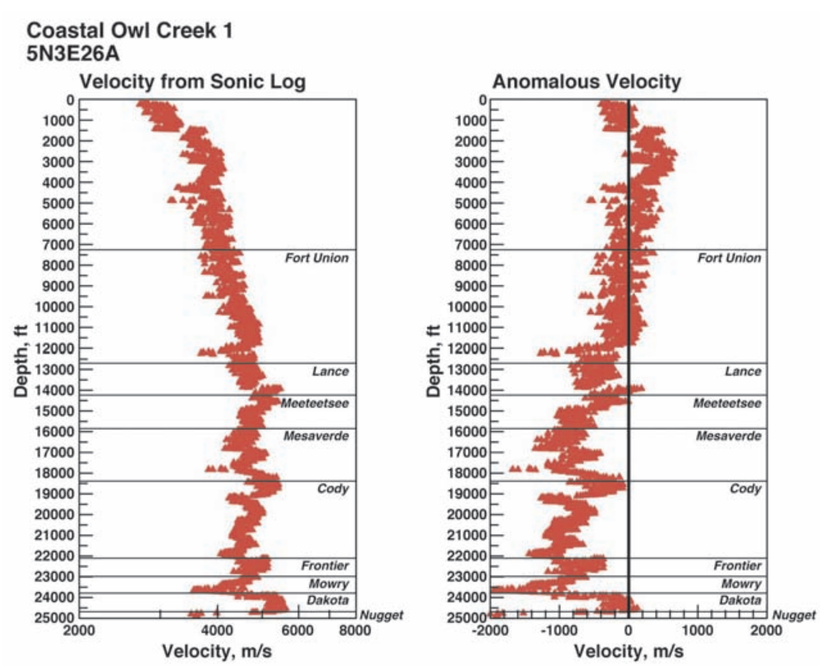

Figure 5. Sonic velocity and anomalous velocity profiles for the Coastal Owl Creek 1 well. The pressure surface boundary is at 11,800 ft.

(Figure 6). The gas-charged, underpressured section can be identified on the anomalous velocity profile by using the pressure data (i.e., DST, RFT, and mud data) (Figure 7).

Determination of Badly Damaged Productive Zones

Because the pressure transition configuration present in the study area was poorly understood or unknown to drillers when many of the RMLB gas stripper wells were drilled (prior to 1990), operators, from experience, assumed they would encounter overpressuring at depth. The drillers' primary concern, with respect to safety and control of the well, was for a transition from normal to overpressure; consequently, they increased mud weights during drilling. However, in the RMLB, underpressuring is often encountered at depth; thus, many of these underpressured zones were drilled with overcompensated mud weights (Figures 6 and 7). In this drilling situation, the potential for bypassing or highly damaging productive zones was *significant* and resulted in wells that produced only a fraction of the available gas.

In order to determine where badly damaged productive zones occur in the study area, mud logs were plotted with anomalous velocity profiles. For example, Figures 6 through 9, which include both mud weight profiles and anomalously velocity profiles, show how mud weights were overcompensated in the underpressured stratigraphic section. Figures 6 shows both

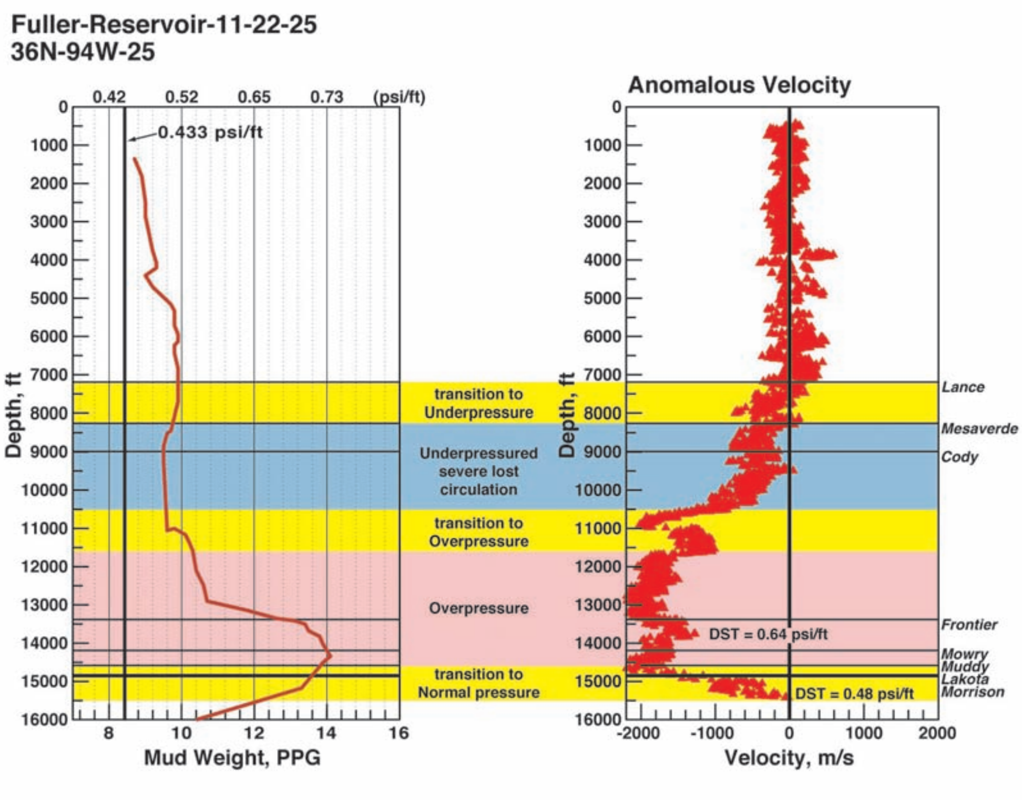

Figure 6. Mud weight profile and anomalous velocity profile for the Fuller Reservoir II 22-25 well. The regional pressure surface boundary is at the top of Lance at 7200 ft depth. The underpressured zone is from 8250 to 10,500 ft depth. The mud weight used to drill the underpressured interval was 9.6 ppg, or significantly overcompensated.

profiles for the Fuller Reservoir II 22-25 well. Here, the regional pressure surface boundary occurs at the top of Lance at 7200 ft depth, and the underpressured zone occurs in the 8250 to 10,500 ft depth interval. The mud weight used to drill this gas-charged underpressured interval was 9.6 ppg, which was significantly overcompensated. In Figure 7, shows both a mud weight profile and anomalous velocity profile for the Ocean Lake Tribal 1 well, the regional pressure surface boundary occurs at 8000 ft depth in the Fort Union Formation, and the underpressured zone occurs in the 8000 to ~13,500 ft depth interval. A pressure gradient 0.39 psi/ft from DST is measured at the depth 10,000 ft, so the mud weights should have been less than the weight of water (i.e., < 8.4 ppg). The mud weights used to drill this underpressured interval were 8.6 to 9.2 ppg, also overcompensated. In Figure 8, the profiles are from the Tribal 1 well. The regional pressure surface boundary is within the Fort Union Formation at 6300 ft depth, and the anomalously pressured zone occurs within the 6300 to ~11,200 ft depth interval. The mud weights used to drill this anomalously underpressured interval were 8.9 to 9.4 ppg, again overcompensated; there is no indication that the upper potion of this anomalously pressured zone is overpressured, but instead is underpressured. In Figure 9, the profiles are for the Federal 13 well in the Washakie Basin, Wyoming. The regional pressure surface boundary occurs at 6500 ft depth in the Fort Union Formation, and the anomalously pressured zone occurs from 6500 to DT. The mud weights used to drill this anomalously underpressured interval were 8.9 to 10.3 ppg, again, an overcompensated mud program.

It is clear from these preliminary results that the mud weights used to drill gas-charged underpressured sections were significantly overcompensated (and potentially damaged the zone) and were common in the both Greater

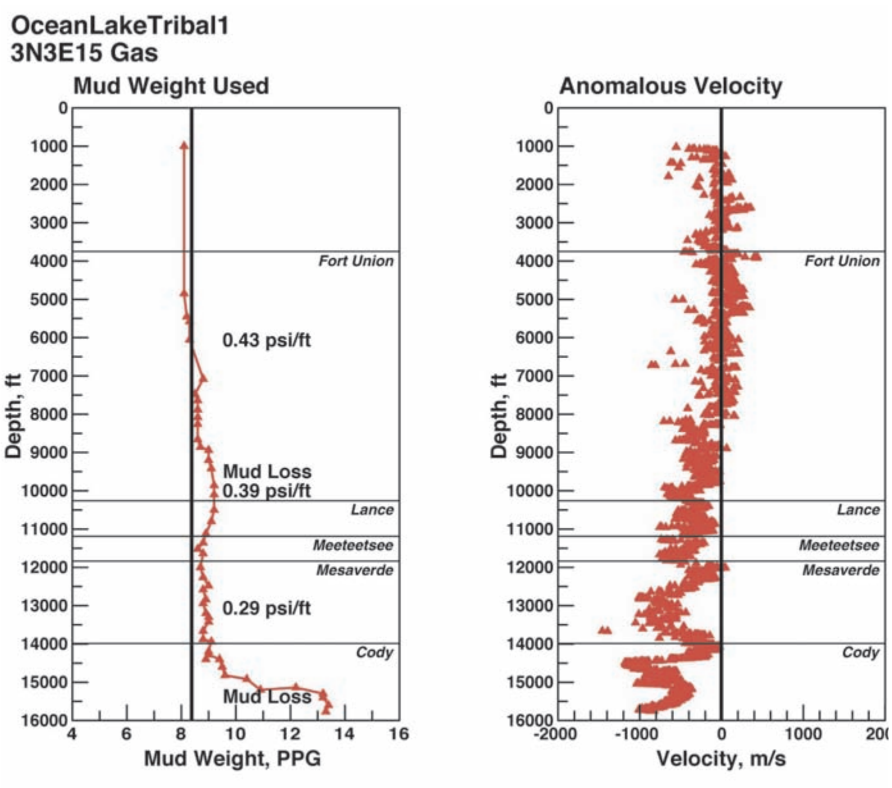

Figure 7. Mud weight profile and anomalous velocity profile for the Ocean Lake Tribal 1 well. The regional pressure surface boundary occurs in the Fort Union Formation at 8000 ft depth. The underpressured zone is from 8000 to ~13,500 ft depth. A pressure gradient 0.39 psi/ft from DST is measured at the depth 10,000 ft, so the mud weights should have been less than the weight of water (i.e., < 8.4 ppg). However, the mud weights used to drill this underpressured interval were 8.6 to 9.2 ppg, also significantly overcompensated.

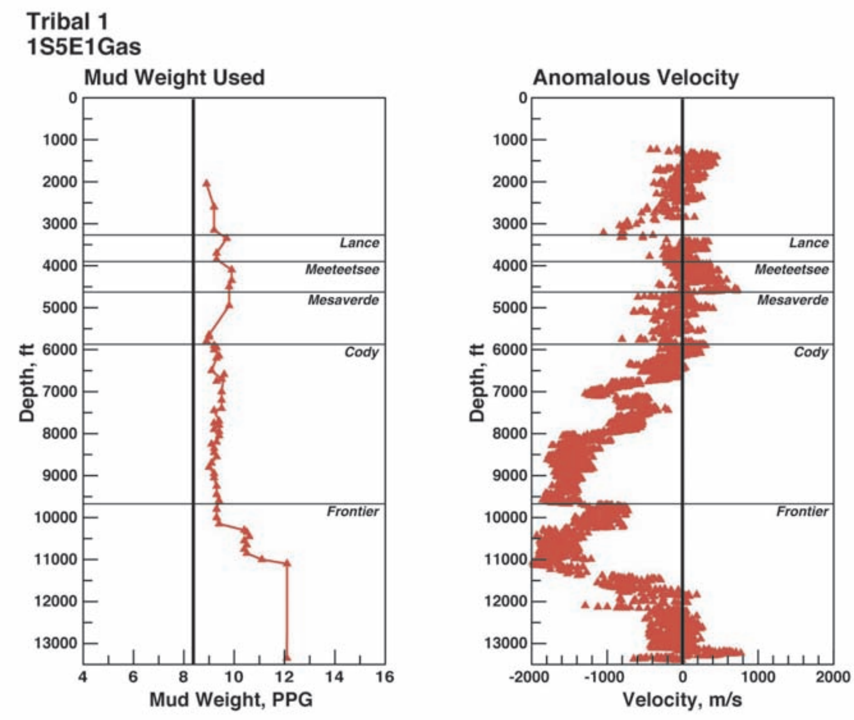

Figure 8. Mud weight profile and anomalous velocity profile for the Tribal 1 well. The regional pressure surface boundary is within the Fort Union Formation at 6300 ft depth. The underpressured zone is from 6300 to about 11,200 ft depth. The mud weights used to drill this interval were 8.9 to 9.4 ppg. There is no indication that the upper potion of the anomalously pressured zone is overpressured rather than underpressured. Thus, the mud weights used to drill the gas-charged, underpressured section were significantly overcompensated

Green River and Wind River basins (Figures 8 and 9). In fact, numerous gas-charged intervals were overcompensated with heavy mud. The logic for these conclusions is as follows:

1. The rock/fluid systems are gas-charged (i.e., have anomalously slow velocities), so they must be either overpressured or underpressured, as they cannot fall on the hydrostatic gradient as a result of the gas charge.
2. If the section being drilled were overpressured, it would have to be drilled with mud weights greater than 8.5-9.0 ppg, otherwise the control of the well would have been lost.
3. If the section being drilled were underpressured (Figure 7), mud weights of 8.5 to 9.0 ppg would be significantly overcompensated.
4. In the examples shown in Figures 8 and 9, the portion of the section of interest is anomalously slow (i.e., gas-charged) and, thus, anomalously pressured. The mud weights are approximately 9 ppg; thus, the rocks are not overpressured. If they are not overpressured or normally pressured, they must be underpressured. If so, the mud weight program utilized in Figures 8 and 9 in the upper portion of the anomalously slow velocity section was grossly overcompensated as this portion of the section was penetrated.

These badly damaged zones still contain a huge gas resource that operators can exploit if they can design effective remediation and recompletion strategies or select new completion zones for gas stripper wells and some abandoned wells. Therefore, it is important to design techniques to identify bypassed pay and highly damaged productive zones in RMLB gas stripper wells, because in most of these wells, these zones are characterized by an underpressured rock-fluid system (Figures 6 and 7).

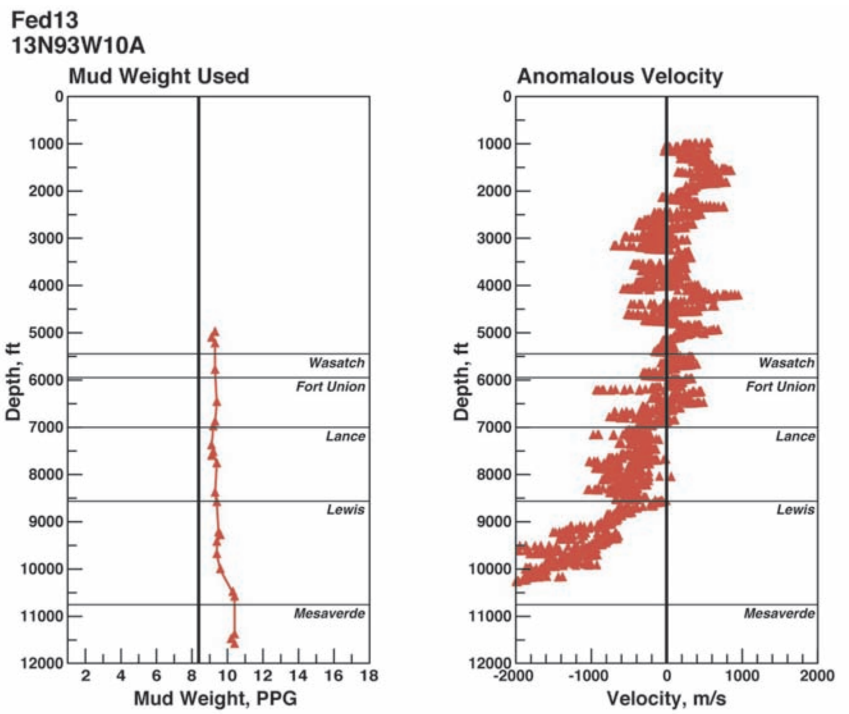

Figure 9. Mud weight profile and anomalous velocity profile for the Federal 13 well, Washakie Basin, WY. The regional pressure surface boundary is within the Fort Union Formation at 6500 ft depth. The anomalously pressured zone is from 6500 to DT. The mud weights used to drill this anomalously underpressured interval were 8.9 to 10.3 ppg, again, overcompensated.

Recent Accomplishments

For 45 wells, we have evaluated mud weights, velocity inversion surfaces, anomalous velocity profiles, lithology, resistivity, porosity, pressure tools, gas shows, and production data. In every case, for the upper portion of the anomalously slow velocity domain (i.e., gas-charged volume), the mud weights were typically 9 to 10 lb/gal. Thus, if any underpressured rock/fluid systems were present in these wells, they would have been badly damaged during drilling. The key question is how significant and widespread are underpressured rock/fluid systems in the Wind River and Greater Green River Basins? If underpressured rock/fluid systems are significant and widespread, there is huge bypassed gas potential in both gas and gas stripper wells.

At present, we are evaluating the answer to the above question based on the 45 wells selected for analysis. This evaluation is taking place according to the following sequence of steps:

1. First, the regional normal velocity/depth trend is removed from the observed sonic velocity/depth profile (Figure 10). The results of this operation are two-fold: (1) isolation of anomalously slow sonic velocities and (2) definition of the regional velocity inversion surface. The isolated anomalously slow velocity domains beneath the regional velocity inversion surface in the RMLB are gas-charged (Surdam, 1997; Surdam, 2001a,b). It is known from previous work that the regional velocity inversion surface is the boundary between normally pressured rock-fluid systems above and anomalously pressured, gas-charged rock-fluid systems below (Figure 10).
2. The next step is to integrate pressure data, derived from drill stem tests and other pressure indicators, with the anomalous velocity profiles (Figure 10). This integration allows underpressured and overpressured portions of the anomalously slow velocity domain to be delineated (Figure 10).

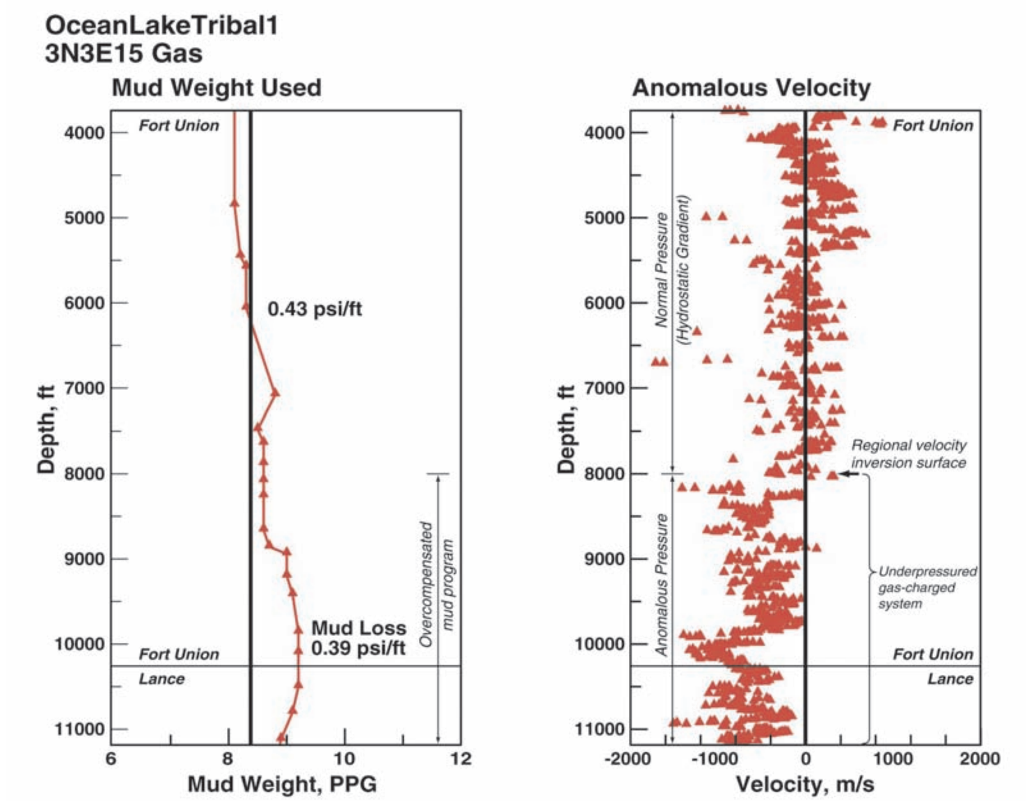

Figure 10. Left: mudweight profile for the Ocean Lake Tribal 1 well, with available pressure gradients from DSTs. Right: Anomalous velocity profile for the same well. Velocity along the regional normal velocity/depth function falls on the vertical black line; velocities falling left of the vertical black line are anomalously slow and indicate rocks will tend to be gas-charged and anomalously pressured.

3. Step three is the evaluation of the distribution of potential reservoir sandstones within the section characterized by anomalously slow velocities and underpressuring (Figure 11). Typically, the relatively thick sandstones within the underpressured anomalously slow velocity domain are characterized by low gamma ray, high resistivity, high density porosity, and low neutron porosity (Figure 11). These log characteristics are compatible with a gas-charged sandstone interpretation. Where possible, information with regard to background gas, gas shows, and gas flows are integrated into the evaluation.

This evaluation is used to determine the presence or absence of underpressured, gas-charged potential reservoir sandstones. From this sequence of steps, it is possible to detect significant thicknesses of underpressured, gas-charged sandstone reservoirs in 30 of the 45 wells studied (Table 1). It is important to note that each of the 30 wells where underpressured, gas-charged reservoirs exist were drilled with 9 to 10 lb/gal mud (i.e., grossly overcompensated mud programs).

This zone of underpressured, gas-charged, rock/fluid has been unrecognized in so many of the RMLB because, relative to the San Juan and Alberta basins, it tends to be thin in most other basins (Figure 12). In the San Juan and

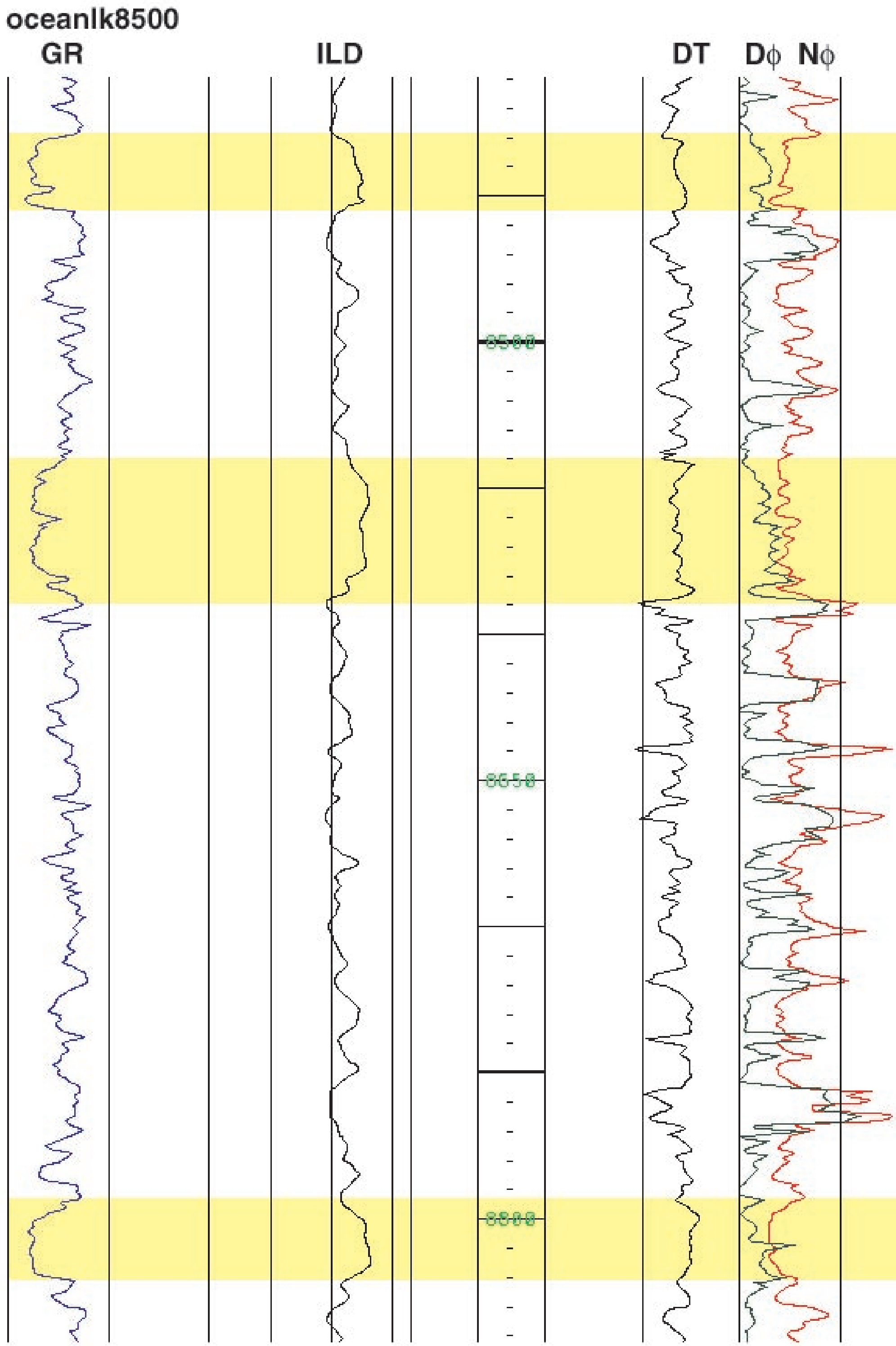

Figure 11. Log suite profiles from a portion (8500-8800 ft) of the Ocean Lake Tribal 1 well. The yellow zones are sandstone intervals that, based on log characteristics, are gas-charged and, from Figure 10, are underpressured.

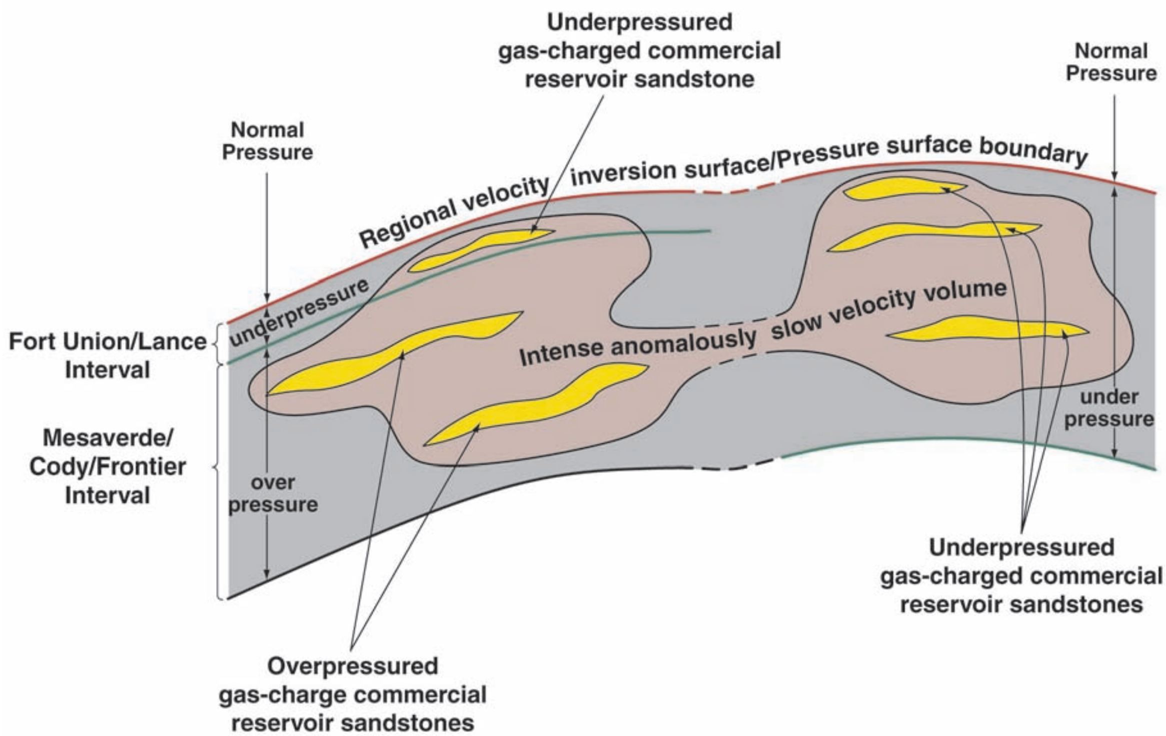

Figure 12. Schematic diagram illustrating the differences in pressure regimes in basins like the San Juan and Alberta basins, as compared to basins like the Wind River and Green River basins. In the San Juan and Alberta basins, the pressure transition is from normal pressure to a thick, underpressured, gas-charged and productive section (right side of diagram). In contrast, in basins like the Wind River and Green River basins, the transition is from normal pressure to a relatively thin, underpressured, gas-charged section, underlain by a relatively thick, overpressured, gas-charged and productive section (left side of diagram).

Alberta basins, operators drill from normally pressured sequences, across the regional velocity inversion surface, into a very thick and productive underpressured section (Figure 12). In contrast, in the other RMLB, operators drill from normally pressured sections, across the regional velocity inversion surface, into a relatively thin and historically unrecognized underpressured, gas-charged section, *then* into a thick, overpressured productive zone. Thus, historically the driller's primary concern has been to prepare for the transition from normal pressure to overpressure; consequently, most wells, excluding the San Juan and Alberta basins, have been drilled with significantly overcompensated mud programs.

Conclusions

It is concluded that, in 30 of the 45 wells studied in the Wind River and Green River basins, there are large columns of rock/fluid that are underpressured and gas-charged. Each of these 30 wells were drilled with significantly overcompensated mud weight programs. Thus, there is high potential for serious damage during the drilling of the underpressured, gas-charged sandstones, or for bypassed pay, over a significant stratigraphic interval.

Future Work

In future work, presently being considered by the Stripper Well Consortium, the IDT team will evaluate the size of the heretofore unrecognized, underpressured gas resource in the RMLB (excluding the San Juan and Alberta basins).

The essential problem that will be addressed is how to delineate underpressured, gas-charged rock/fluid columns just below the regional velocity inversion surface in the Wind River Basin. This basin was chosen for study because the following data are available to IDT: (1) ~3000 mi of 2-D seismic lines; (2) 200 log suites and thousands of mud logs and 10,000 DSTs; and (3) U.S.G.S. depositional models and detailed analyses of the stratigraphic frameworks.

This work will include the following tasks: (1) isolate those portions of the Lance (uppermost Cretaceous) and Fort Union (lowermost Tertiary) formations below the regional velocity inversion surface characterized by anomalously slow sonic/seismic interval velocities (i.e., gas-charged rock/fluid systems); (2) construct a 3-D volume of gas-charged rock/fluid systems; (3) integrate mud logs and DSTs with the volume to determine underpressured areas; (4) determine the spatial distribution of commercial gas reservoirs in the study interval; (5) determine where Lance-Fort Union potential reservoir rock volumes intersect the underpressured gas-charged volume; and (6) evaluate the size of the unexploited gas resource in underpressured, gas-charged sections of the Lance-Fort Union reservoir volume by approximating petrophysical properties of the Lance-Fort Union clastic reservoir rocks.

The results from the project will allow operators to:

- Determine the size, configuration, and importance of underpressured, gas-charged hydrocarbon resources beneath the regional velocity inversion surface in the WRB;
- Delineate sections likely to contain badly damaged or bypassed productive zones;
- Design new drilling and completion strategies that will allow the maximum gas production from underpressured, gas-charged reservoirs; and
- Determine the potential for similar assets in RMLB other than the Alberta and San Juan basins.

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APPENDIX D:

2002 PROJECT FINAL REPORTS

DOE NETL Prime Award No. DE-FC26-00NT41025

Subcontract No.2052-BEDC-DOE-1025

BEDCO
Final Report
Feb. 14, 2002 to May 15, 2002
Submitted to:

J. Morrison
The Penn State University
C-211 Coal Utilization Laboratory
University Park, Pa. 16802-2308

Title of Project: "Design Development and in Well Testing of a Prototype Tool for in Well Enhancement of Recovery of Natural Gas" Via use of a 'Gas Operated Automatic Lift Pump"

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October 2002

Accepted by:

DISCLAIMER

Abstract

A 'Gas Operated Automated Lift Pump' has been conceptually developed constructed in prototype and determined to be applicable for use in removing fluids from "stripper wells" thereby increasing production of natural gas. Bench scale and laboratory test of the key tool component, the automated pressure controlled valve assembly, has established the potential applicability of a prototype tool in watered out stripper wells. Tool applicability is targeted to operating conditions of 50 to 600 psi down hole pressure with brine and fluid lift capacity varying from 0.1 to 6.0+ BBL/ tool cycle. In field precursor testing of a pilot predecessor tool of larger dimensions and weight than that targeted for fabrication and deployment as part of the SWC program has shown promising results. A precursor field test of tool [s] have shown improved natural gas production 1.6 X to 2.4X, regular automatic cycling of tool [1 Trip each 1 –1.5 Day] and auto lifting of brines [0.33 – 1.5Bbl/cycle] from a brine producing natural gas stripper well. Field testing of the above referenced designed prototype tool for this phase of the project showed similar brine production [0.25 to 1 Bbl/ tool run with 1 to 2 day cycles] and frequency of tool cycles during the early period of field trials. Field trials of the new prototype tool evidenced metallurgy problems in materials construction compatibility resulting in premature actuator failure and decreasing frequency of tool runs and lesser quantity of fluids production with each subsequent tool trip. Field and laboratory analysis have diagnosed the problem and designed a remedy for further in field-testing. This premature failure was diagnosed as corrosion on one of the actuator components. The problem occurred as a function of miniaturizing of components to achieve a desired, "well tender friendly" smaller tool configuration. Additional lab trials and in field testing of the smaller prototype tool with a modified more corrosive resistant actuator are scheduled for the 4th calendar quarter of 2002. This work will be conducted by BEDCO as part of its on going commitment to establish working G.O.A.L. Tool technology to assist in the production of gas and oil from the nations aging stripper wells. This work will be supported by the SWC and NYSERDA in a follow on award for field trials of G.O.A.L. PetroPump Tools.

The cost of the G.O.A.L. PetroPump and the attendant well head modifications in comparison to the improvements of gas production achieved by the prototype tools, at current market prices of $3.00 Mcf, suggest a potential payback on capital investment of 1 to 1.5 years.

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INTRODUCTION

The following is the final report under DOE NETL Prime Award No. DE-FC26-00NT41025, Subcontract No.2052-BEDC-DOE-1025 on the development of a prototype tool for the automatic lifting of brines with subsequent improved gas flow production from watered out stripper wells. This feat is accomplished through the use of an on tool automated pressure-sensing/ actuating value that is preset to pass through a predetermined volume of brine with subsequent lifting of that brine to a surface process unit and brine tank. The energy for that lift is powered solely by in well geologic formation pressure.

EXECUTIVE SUMMARY

More than 8% of the US natural gas production is derived from "Stripper Wells" averaging approximately 15-mcf/ day. Much of the United States and the world's natural gas producing wells suffer from declining and restricted production due to the presence and build up of brines in the well bore. Conventional techniques for addressing and or removal of the brine are cumbersome and costly. The scope of this project is to develop an alternative technology [total fluids pump] for the automatic lifting of that brine/ fluid to the surface using in well down hole pressure to activate an in tool valve. This sensing control valve is automatically held open by an internal pressure sensing mechanism allowing the tool to drop into the fluid column in the well. Passage ways through the tool allow passage and accumulation of brine atop the tool to a preset column thickness at which time the on tool pressure sensing mechanism closes the tool valve. This closure is accomplished via the combined hydrostatic pressure of the brine atop the tool and system backpressure. An in well down hole seal of the tool to the casing is accomplished by a set of dual flex cups which surround the tool and make circular contact with the well casing. Subsequently tool and fluid column are lifted to the surface driven by below tool formation pressure [in well below tool pressure].

In the work completed to date on this project BEDCO has confirmed the need for and applicability of an automated tool, which will remove, accumulated fluids [brines] from gas wells and increase gas flow. BEDCO has confirmed these needs and results of increased gas yield post brine removal from wells via meetings, work sessions, well records review, interviews with well field owners and operators and preliminary production response from predecessor tools. These owners and operators currently use sundry methods of brine removal to produce gas from their stripper wells. Interviews with both well owners and operators speak to a common problem in production of natural gas from stripper wells using conventionally available techniques. That problem being, that current production techniques and tools for removal of fluids [Brines] leads to intermittent and often irregular production of gas from stripper wells and certain process unit problems such as winter icing. A need for regular automated fluid removal and more uniform gas production is desired and needed.

BEDCO has produced and bench tested a prototype tool to meet industry needs and simulated in field testing with a 98% adherence/ correlation to the designed tool plan.

BEDCO has further begun to define the numbers and types of wells applicable for such an automated tool through technical work and review sessions evaluating tens to hundreds of “stripper wells’ production records with a regional natural gas producer. The number of wells for which the technology is applicable in the Appalachian Region, in the tools current configuration [i.e. sized for 4 to 6 inch ID wells], are numbered in the high thousands. Through out the country, and with further miniaturization of certain tool components the, wells for which the technology is applicable number into the tens of thousands.

The completed work to date on bench tools and prototype tools for field use has focused on tool design and construction of durable materials that are tolerant of down well physical and chemical conditions. To that end materials of construction are Hastelloy, 316 stainless steel for all tool body parts and condensate tolerant synthetics materials for tool sealing cups and BUNA-N materials for automated valve seats. Tooling and machining of components, assembly processes for components and current generation production prototypes are so configured to match with or lend themselves to standard oil and gas field specifications and conditions of service tool [s] availability and technician capability. A field demonstration tool of 32” in length and 42# of total weight has been manufactured and is under ongoing bench testing to determine performance characteristics and simulate in well/ in field-testing. Installation for this new tool design in a chosen Lenape Resources Inc. natural gas well # 52 occurred in March 2002. The well physical characteristics are show in Table 1 - 1 in the Appendix.

It has been determined from predecessor [larger] tool testing that variable tool response is necessary to optimize the performance to low pressure wells and low volume fluid production from certain stripper wells. To address such needs BEDCO has developed bench test apparatus for mock up tool configurations to simulate and address the need for variable stroke and valve seat configuration design to address variable well conditions related to geology conditions and life cycle of the well. Further this apparatus has been and is used to calibrate assembled tools for in field-testing. As noted previous, in field tool testing with prior generation pilot tools has confirmed this need and ability to adjust the tool to wells with lower down hole to well head pressure differentials and lighter brine [fluids] loads. It is also apparent from this testing that smaller pressure sensor control mechanisms would allow for construction of a smaller tool and accommodate a wider selection of candidate wells. Producers express interest for a 2 to 2.5” diameter tool.

Development of real time metrics which will quantify the results of the tool deployment and in well testing as well as provide detailed information for refinement of construction and operation of the tool are critical to the project success. We have determined that the oil and gas industry has begun to address these needs with a limited number of first generation continuous data loggers targeted to collect some of the key pressure and flow data associated with operating wells. BEDCO has further ‘in field” deployed and initiated configuration of one such data logger unit on a test well to confirm its use and applicability to the “Prototype Tool”.

EXPERIMENTAL

SIMULATION AND ANALYSIS

Analytic modeling was developed to assess candidate fluid lift pump configurations. Analytic simulations indicated that the pressure at which a sensor controlled valve will closed is controlled, to a first order, by the sensor-actuator compression ratio, spring force plus valve and shaft weight, and the initial sensor-actuator charge pressure and charge temperature. Additionally it was concluded analytically, that the pressure at which a sensor-actuator controlled valve will open, once closed, is related, to a first order, only to the ratio of the sensor-actuator cross-sectional area to the valve cross-sectional area, the pressure above the valve, and the pressure below the valve. Based on these understandings, various valve and sensor-actuator geometry were analyzed and alternative configurations and operating strategies were evaluated.

DEVELOPMENT TESTING

A development test program was designed to correlate the analytic modeling and to provide calibrations for development of fluid lift pumps.

The test vehicle consisted of a tubular section containing, and supporting, a sensor-actuator assembly. This was attached to a cylindrical valve seat assemble. A valve shaft was attached to the lower [free] end of the sensor-actuator in such a way that as gas pressure [forces] compressed the sensor-actuator the valve head was pulled up into the valve seat. Upper and lower pressure caps were attached to the cylindrical assembly. Bottled nitrogen plus control valves and gauges completed the test set up. Testing was also conducted with test items immersed at pressure under water. The results indicate no significant difference between water and air [gas] testing.

Tests were initiated with the sensor-actuator-controlled valve in the open position. Gas pressure was increased below the valve, filling and pressurizing the total test vehicle, until the sensor-actuator assembly compressed closing the valve. This simulated the fluid pump descending into the well, being exposed to the flow pressure and hydrostatic fluid pressure, and eventually shutting in the well. The testing established the validity of the analytic modeling of in-well valve closing providing an analytic basis for design modifications.

Each test was continued to simulate the fluid pump arriving at the well head. The pressure above the sensor-actuator-controlled valve was bled off; corresponding to that which would be dissipated into the tank and sales line as the fluid pump approached the surface. The pressure above the sensor-actuator, in the test vehicle, was varied parametrically from one to five atmospheres to assess the validity of the analytical modeling. The pressure below the valve, and sensor-actuator, was reduced until the valve opened. This represented the reduction of well flow pressure that would result as the gas was discharged from below the liquid pump. Once again, the experimental data was in good agreement with analytic predictions of the conditions necessary for valve opening. Analytic modeling was used to evaluate alternative fluid pump designs and operating strategies.

FLUID PUMP CONFIGURATIONS

Two sensor-actuator diameters and several valve head configurations were tested over a range of simulated operating conditions. A liquid pump design was tentatively selected, fabricated and tested. Sensor-actuator compression ratios were varied (stroke adjustments) and sensor-actuator charge pressures were selected parametrically to characterize the liquid pump development model. Figure 1 represents sample results of development testing for the selected configuration (hundreds of test have been conducted with a variety of configurations).

FIGURE 1 Gas Operated Automatic Liquid Pumping System (fluid pump)

Bench testing of TOOL #1 with a reduced stroke. August 10, 2001

Summary: Calibration testing of Tool #1 was conducted with a reduced stroke of about 1.05"

Test Results: (Pressure are PSIG) Stroke about 1.05 inches (+\- .02")

Charge Pressure	Valve Closing Pressure	Pressure above Valve At Valve Opening	Opening Pressure	Absolute Pressures Calculations Pcharge	Pclose	Popen	Po/Pc	Pa/Pc
20	58	20	32	34.70	72.70	46.70	0.64	0.48
20	58	0	20	34.70	72.70	34.70	0.48	0.20
20	55	0	18	34.70	69.70	32.70	0.47	0.21
20	56	0	18	34.70	70.70	32.70	0.46	0.21
20	55	30	40	34.70	69.70	54.70	0.78	0.64
20	55	30	40	34.70	69.70	54.70	0.78	0.64
20	57	20	32	34.70	71.70	46.70	0.65	0.48
30	70	30	43	44.70	84.70	57.70	0.68	0.53
30	70	30	44	44.70	84.70	58.70	0.69	0.53
30	73	30	44	44.70	87.70	58.70	0.67	0.51
30	70	50	59	44.70	84.70	73.70	0.87	0.76
30	70	60	65	44.70	84.70	79.70	0.94	0.88
50	106	50	66	64.70	120.70	80.70	0.67	0.54
50	107	30	51	64.70	121.70	65.70	0.54	0.37
50	107	20	42	64.70	121.70	56.70	0.47	0.29

In all testing, the calculated absolute pressure ratios (that is, valve opening pressure/valve closing pressure, and pressure above the valve at opening/valve closing pressure) can be characterized by a straight line plot, the slope being determined by the ratio of the sensor-actuator effective cross-sectional area to the valve seating cross-sectional area.

Specifications have been developed for the fabrication of two alternative sensor-actuator configurations; one with a reduced diameter (1.70" vs. 2"), and both with longer available strokes (20% increase). Discussions are in process with suppliers.

RESULTS AND DISCUSSIONS

The project has been broken down into six major tasks. Those work tasks and the status of activities on those tasks are outlined below:

1.0 COMPLETE DESIGN OF PROTOTYPE TOOL

1.1 The project senior engineering, senior manufacturing and scientific personnel have conducted meetings and work sessions with field engineering/ well operations personnel to outline field durability needs, assembly, adjustment, ease of installation and service specifications for the prototype tools. Findings to date indicate the obvious needs for chemical compatibility with down hole chemistry. This is addressed via the use of Hastelloy, 316 stainless steel metallurgy and valve seat [Buna N] and sealing cup chemistry that will be tolerant of both brine and condensate. Additional findings go to near term application of the tool in 4 inch casing wells and longer term application of tool use in tubing of 2.5 inch or smaller diameter. Immediate needs for the 4 inch cased wells need to address tool total weight, total length, and assembly/ deployment/disassembly of tool components in the field.

1.2 Specific elements that have been addressed are the length, weight and tool diameter to allow for maximum use in varying type of wells and minimum amount of reconfiguration of well head and associated cost. Ancestral tools were in excess of 6 feet in length and 105 pounds in weight. Operating predecessor prototypes for the tool under current design/construction reduced length to 46 inches and weight to ~54 pounds. The tool constructed and bench testing for deployment and testing for the SWC 2002 project is 32" in length and weighs ~ 42 pounds. This design and construction configuration allows ease of deployment of the G.O.A.L. PetroPump and retrieval by a well tender with minimal changes in configuration to a typical well head lubricator.

1.3 Another specific element determined in field meetings for tool modification is the component assembly characteristics. Field assembly, disassembly and adjustment must be possible with the fewest number of field tools and personnel to assist. To that end, tool design and construction has been simplified and addressed to oil and gas industry standards. This includes only three- [3] field serviceable disconnects and these are constructed with standard 6 pitch General Acme threads. Components have been reduced from 27 or more in predecessor tools to 14. Basic material for the tool body is commercially available durable 316 stainless steel. Minimum steps for tool assembly and large milled tool flat areas [wrench flats] complete the simplified design and assembly. This design/ construction/ assembly approach all lends itself to service and maintenance work by standard industry tools [i.e. 36" and 48" pipe wrench, 18" and 24" adjustable wrench and 3# and 5# hammer].

1.4 Field and bench testing has lead to further tool modification of valve seal mechanism improving simulated and field confirmed results with the SWC new designed tool.

1.4 **Project senior engineering, manufacturing and scientific personnel have conducted work sessions and have completed a prototype tool in conjunction with the specialized machining firm of Eagle Tool and Die. The tool has completed bench testing and well simulation testing. The, "user friendly", smaller tool was installed in a test wells in March 2002. To achieve the above referenced reduced size and weight of tool, senior engineering designed for the use of a new design and constructed [20 % smaller diameter] self actuating control mechanism for the automated control valve. This major change in design and construction fostered other reductions and size leading to the decreased tool length of ~15" from predecessor tools to the current 32" prototype for SWC in well demonstration and decrease in weight of ~12 pounds to a current weight of ~42 pounds. These represent significant changes, which lend them self to one-man installation and ease of use and retrieval. In process drawings and list of materials stock for machining of components have been simplified in form and reduced in total numbers of components to 14 from 27. The drawings and materials stock list are completed. The documents have been reviewed by the joint team to determine the possibility of further simplification and reduction in component parts. Valve actuator protection against over-pressurization from ambient forces down well was determined as a potential factor in tool operations and design/ construct compensated.**

1.5 **Project senior engineering in conjunction with the manufacturing director have designed, constructed, modified and refined a bench testing device on which the prototype tool has and was tested prior to and post in field testing. Lab testing of varying pressure [equating to differing in well brine head/ pressure] simulations has been tested to confirm viability and operational integrity of the constructed bench testing equipment and tool critical components. Changes in the actuator stroke and seating area of the self actuating valve assemble have been subject to test to allow for and confirm potential for operation in low pressure and small brine/ fluid load environments.**

1.6 **Specifications and modifications to the pressure sensing [valve control] device for the operation of the in tool automatic valve have been developed from the above completed meetings, work sessions and test stand work with specific reference to targeted installation wells.**

2.0 CONSTRUCT AND BENCH TEST PROTOTYPE TOOL

2.1 **The prototype tool was constructed and bench tested against design parameters to which it adhered with greater than 98% correlation. The tool was in lab modified to accommodate learned information from predecessor on going field test to avert over pressurization by ambient forces in down hole conditions. Well operation simulation testing is on going as part of company QA/QC and product evolution.**

3.0 SELECT CANDIDATE WELLS

3.1 Meetings and work sessions with Lenape Resources Inc. have been conducted to assemble a list of candidate wells and choose a well for testing of the "Prototype Tool".

3.2 Starting with a list of more than 200 operating and shut in stripper wells a short list of more than 50 wells was assembled. This short list was further refined to 2 target wells. From those two alternative wells, LRI # 52 was chosen for testing.

3.3 Considerations evaluated in choosing LRI # 52 include total yield over time since completion, current yield, and history of fluid production, decline curves and previous testing database.

- As noted above, two alternative test wells were considered. LRI # 52 and LRI #29 were subsequently evaluated for field tool use and evaluation.
- Data on these wells is shown in the appendices
- LRI # 52 had been previously tested with predecessor tools and has the most complete available history of technical data for evaluation and comparison of the many variables associated with gas production which makes it a technical favorite for testing and analysis. The well however is associated with a sales/ gathering system which periodically [especially during low commercial gas demand] that pressures up to in excess of 100 psi versus normal operating pressures of 50 psi making gas production from the well under those conditions onerous.
- Well LRI # 29 as a candidate has less data base and history of close watched operations, but has an advantage of being produced into a sales line with an LRI owned/ operated compressor station which theoretically can minimize wide/ wild swings of back-pressure on the system.

3.5 Associated data on water/ brine production on these wells and other back up candidate wells is continuing to be assembled along with well response [production] information related to intermittent or regular removal of those brines. The final choice of test well was made upon data review and completion of tool assembly with in field-testing initiated in March of 2002 on well # 52.

4.0 TEST WELL PRODUCTION

4.1 Quantification of gas production before, during and post "Prototype Tool' deployment is a key element on the development of metrics to confirm applicability and success of the tool. Current technology on most wells for quantification of gas yield and pressure is performed by analogue instrumentation. This analogue instrumentation is tied to a specific orifice plate size in the well process unit and recorded on a circular 'pie' chart. The charts are subsequently integrated and quantified by third party off site contractors at a later date.

4.2 The project scientist and engineers have assembled some of this analogue data as it relates to the target well for in field-testing and continue to assemble review and interpret this historic data. Production from this well meets targeted test parameters. Those parameters include down hole pressure and historic production challenges which between the period of 1994 to 1999 showing low to no gas production from this well # 52 prior to physical swabbing / brine removal with a work over rig to remove several tens of barrels of brine.

4.3 In field process production data from a larger and heavier predecessor tool is also undergoing analysis and was used in final fabrication of the SWC prototype test tool and wellhead modification parameters. Reduced data to date from this predecessor tools shows an increase gas production from [2] two stripper wells of >1.6X to 2.4X. Regular tool automatic cycles at 1cycle each 1-1.5 days with 0.3 to 0.8 barrels of fluid produced per cycle @ 15 to 20 cycles/ month yielding 8 to 10 barrels/ month of brine are recorded. In well and at well head operating conditions evidence typical pressure ranges expected for the SWC test of 50 to 60 psi backpressure and down hole pressure conditions of 100 to 150 psi.

4.4 Real time comprehensive data collection of well head, process unit and sales line pressure and flow are critical to thorough comprehension of well and tool operation. To that end BEDCO has acquired and deployed a digital recording data logger to capture this type of information. Digital data loggers can collect comprehensive "real time" data at the well head and the process unit. Technical information was first assembled on
manufactures and suppliers of continuous recording digital data loggers [well head computers] to collect and log both volume yield and pressure through out the well head and process unit system.

4.5 Bids were solicited for the purchase of a unit most applicable to project needs.

4.6 A successful bidder/ supplier of the well head data logger has been selected. The unit wellhead computer, solar panel and battery] has been purchased installed and field-tested.

4.7 The components of the unit have been field installed on a chosen data collection/ confirmation well in the Lenape Resources System. Unit software and sensors have been installed and calibrated. Results to date show accurate relative correlation with analogue recording charts on the well and the ability to collect and recorded data in digital form on as frequent as 1-minute intervals. Down load of system data via cellular link has been proven viable. Soft ware challenges in manipulating the data for accurate/ absolute correlation/ comparison on a 1 to 1 basis were worked on by BEDCO and the equipment manufacturer to achieve in field data collection/ recording and telephonic down loading success.

4.9 Preliminary field recorded data has been retrieved, downloaded and formatted for correlation with the analogue data from the well. An example of incremental data being recorded is presented in Figure 2. Daily summary data is also available.

Figure 2

HOURLY REPORT
FLOW AUTOMATION CORP.
HOUSTON, TEXAS
DATE: 08/03/01

METER NAME: METER RUN #1 TIME: 05:20:33

CONFIGURATION DATA

Contract Hour	08:00	Spec. Gravity	0.6	Mole % CO2	0.0
Mole % N2	0.0	Energy Content	1000.0	Pipe Diameter	1.987
Orifice Bore	0.375	Tap Config.	Flange	Tap Location	Downstream
Temperature Base	60.0	Pressure Base	14.65	Atmos. Pressure	14.7
Low DP Cut-Off	0.5	Fpv Method	AGA8 Gross	2530 Method	2530-1992
Fwv Method	Manual	Fwv Factor	1.0	Water Content	1.0
Well Stream	Enabled	Well Stream Val.	1.0		

DATE	TIME	VOLUME MSCF	ENERGY MMBTU	AVG SQRT (DP * AP)	AVG. DP IN H20	AVG. P PSIG	AVG. T DEG. F
07/17/01	08:00	0.1699	0.1699	9.18453	1.31	51.6	1.89
07/17/01	08:30	0.1874	0.1874	9.71828	1.47	51.46	1.86
07/17/01	09:00	0.1871	0.1871	9.68400	1.46	51.3	1.84
07/17/01	09:30	0.1874	0.1874	9.68333	1.47	51.02	1.79
07/17/01	10:00	0.2043	0.2043	10.45441	1.73	50.06	1.62
07/17/01	10:30	0.1855	0.1855	9.60922	1.49	49.5	1.51
07/17/01	11:00	0.1714	0.1714	9.05914	1.32	49.46	1.5
07/17/01	11:30	0.1781	0.1781	9.23295	1.36	49.73	1.54
07/17/01	12:00	0.1902	0.1902	9.81453	1.53	50.06	1.59
07/17/01	12:30	0.1855	0.1855	9.48633	1.43	50.07	1.58
07/17/01	13:00	0.1693	0.1693	9.09532	1.32	50.15	1.6
07/17/01	13:30	0.1245	0.1245	8.77455	1.22	50.9	1.73
07/17/01	14:00	0.1014	0.1014	7.63768	0.87	53.57	2.2
07/17/01	14:30	0.2102	0.2102	10.66151	1.69	54.2	2.32

4.8 The “Data Logger” programming is being further addressed to provide more application to project needs.

4.10 Software and formatting components were reviewed and modified to meet project data needs. Additional considerations for future use include transducer outputs and event indicators (surface arrival and departure of the fluid pump) are being considered for incorporation in the status reports.

5.0 EVALUATION OF PERFORMANCE

5.1 Well # 52 tool installation took place in March of 2002 with, testing in March, April, May, June and July of 2002. Gas gathering system pressure back up / increases in sales line backpressure were coincident with tool installation in March of 2002 and made initial tool runs and data interpretation awkward. Sales line compressor shut down [s] and service work effectively "pressured out" the tool from running for the first several weeks of operation and testing. During this period line pressures measured at 65 to 70 psi. Well head shut in pressure for LRI # 52 during this same period measured as low as 85 psi. In general a 12-psi pressure differential between well and sales line is required to operate the tool. Tool runs during this period were sporadic and variable in terms of fluid production and post tool run gas production. Fluids production with tool runs varied from 0 [zero] to 0.33 Bbls per run. Gas production for the period varied from a high of 14. 7 mcf/d to a low of 7 mcf/d. At the maximum value the gas production and fluid production were similar to the predecessor BEDCO tool and much higher [>60%] than the standard casing plunger used in this well in 2000 and previous years. At the low production of 7 mcf/d the tool and well were producing on average 1 mcf/d less than the average production achieved by the standard casing plunger. All yields were greater than production historically achieved using tubing alone.

5.2 Observations of prototype tool runs, brine production and gas production from well # 52 during this period of unusually unstable line pressures over several months indicated a general decline in fluid production and decrease in gas production post each tool run. In all two different tools [the second tool at BEDCO cost and expense, as it was not budgeted for in the SWC work plan] were subject to in well/ in field-testing. Both evidenced a similar pattern of performance in well # 52. As such, this portion of the test was reluctantly terminated in early August of 2002 and the tools were returned to BEDCO facility for preliminary evaluation. Physical observations of the prototype tool valve assembly indicated a misalignment of the valve and valve seat. This mis-alignment appeared to stem from the size reduction efforts, which removed certain valve stem guides. This misalignment alone did not preclude tool operations when bench tested both pre and post well installation and operations. The second more profound discovery of ex-situ well, in laboratory, testing was the appearance of slow pressure loss from the actuator assembly. This pressure loss was observed to occur over a period of hours to days on the tools used and retrieved from well # 52. As the actuator is a sealed system, the immediate source of the leakage/ failure was not readily apparent. The actuators were returned to the manufacturer for destructive analysis testing. Upon arrival at the manufacturer, the actuators were first re-subjected to a water bath pressure test to confirm absence of integrity as found in the BEDCO facility. Confirmation of pressure leakage from the assembly was made. The actuators were subsequently disassembled and examined under high magnification. This examination revealed corrosion holes in the actuator. The location of the corrosion holes were located on the stainless steel side of a Hastelloy- stainless weld line. Both tool actuators showed a similar failure pattern. Research into the problem shows an elevated corrosion index potential between Hastelloy and stainless steel metals. This corrosive potential in the construction of the actuator was compounded by the welding of the stainless steel to the Hastelloy and certain physical restrictions in the fluid passage through the actuator which caused brine [15 – 20 % NaCl] to accumulate adjacent to the welds where the corrosion effects were concentrated.

5.3 Tool design modifications have been made. These modifications include a support mechanism for the valve and valve seat assembly, which will improve alignment and increase concentricity of valve and seat in the tool. This should further reduce potential for seating problems or leakage of the valve once closed and sealed. The more important remedy is a metallurgy change in the contact area [reduce corrosive index potential] between the stainless steel end fitting and the Hastelloy actuator. This metallurgy change has been coupled with a physical modification to the actuator which eliminates blind passages in the tool, which can trap brine and there by concentrate their corrosive effects. BEDCO has self-funded these design modifications and manufacturing of new actuators outside of the SWC sponsorship on the project. Delivery of the new actuators, lab and field-testing are targeted for November 2002.

5.4 Post the determination of the prototype [smaller tool] actuator under performance in August of 2002, BEDCO re-installed a predecessor larger tool in well # 52 to confirm applicability of the technology. This earlier version, larger, somewhat more cumbersome, tool was deployed in late August of 2002. The tool was set with an increased actuator pressure to accommodate accumulated brine not removed during the previous testing. The tool target was to retrieve 0.75+ Bbl of brine on each tool run. Observations during the month of September 2002 showed 5 to 7 tool runs per week yielding 0.75 to 1.0 Bbl of brine per trip. Gas yield after each of the trips has averaged 17.5 mcf/d. The brine production is ~ 2 fold greater than during previous tool test and gas yields ~ 15 to 20% greater. Comments by the well tender post the old tool re-deployment were, "gee that well just gets better and better". Similar results were achieved during the first 3 weeks of October 2002.

5.5 Qualitative evaluation and limited comparison of conventional brine removal techniques commonly deployed in similar wells to the chosen test well is given below as a compilation of information in an anecdotal format developed from interviews with well operators.

Existing methods for brine removal in area Medina Fm. wells more commonly include:

[Note: These methods are common to other Geologic Fm. and wells]

- **Periodic swabbing with a "work over" rig to remove accumulated brines and temporarily restore gas flow, requiring a normal two man complement, appropriate swabbing tools, equipment and investment of several hours total time for a 3000 to 4000' well.**
- **Installation of casing swabs that operate by dropping of the mechanical operated casing swab to a preset stand. When the tool strikes the stand it mechanically closes a valve regardless of the height of column of fluid atop the tool and regardless of the pressure below the tool to lift fluid column and tool weight to the surface. These types of tools normally require manual release and often man assisted recovery.**
- **Installation of smaller diameter tubing in 4 to 6 inch wells [commonly 1.5 to 2.5" internal diameter tubing] targeted to allow older production gas wells with declining volume and reducing pressure to lift accumulating fluid from the well to the surface via capillary action in the smaller tubing. This technical approach is often employed with the periodic shut in of the well to increase down hole pressure to a level sufficiently high that upon reopening of the well will purge the tubing of the brine/ fluid column. This method also often employs the use of surfactants "soap sticks" to disperse the brine into a foam and "lighten" the fluid column for purging to the surface, the process unit and the brine tank.**

- Tubing rabbits are another technology deployed to produce gas from these types of stripper wells via the periodic purging of fluids from the tubing column. The rabbits are in general a smaller version of the mechanical swab tools with similar associated challenges of mechanical and man-assisted operation.

All these above technology assisted improvements for fluid removal have a common need for manpower assistance and or some add on well external pressure or electronic activated semi-automated controller. Dropping and retrieval of tools [casing swabs and rabbits] involve the need for periodic service [release and retrieval] by a well tender, down time on the well production and or some external assistance such as mechanical or electric timers for dropping of tools. Periodic swabbing by a work over rig is the most labor intensive and least cost effective of all methods. Tubing and soaping to lift fluids similarly results in well production down time during periods of well shut in to build pressure to purge the well and also require appropriate manpower.

Interviews with well tenders and operators alike when questioned, what dictates the frequency of servicing a well where one or the other of the above technology is deployed? Most record a common refrain, "When there is sufficient time to get to it [the well]". As such production is highly dependent upon the frequency of service by the operator and punctuated by periods of non-production and spike production.

One such interview on frequency of service and method of operation with a well tender of more than 30 years experience focused on his experience with the most comparable [albeit not operationally comparable to the design and preliminary operational results of the G.O.A.L. PetroPump] technologies of casing swabs/ mechanical swabs/ 'dumb swabs. Questions posed to operator were simply when and how do you decide to deploy or "Drop" a mechanical swab tool and what do you do if problems arise with it cycling/ returning to the surface with brine:

- **The candid response was, as a conscientious operator he tries to inspect the well every two days and make a qualitative determination of well production and wellhead pressure. At such time as he determines from his inspection and interpretation of the process unit analogue volume/ flow production chart, pressure reading at the process unit and possibly a well head pressure reading that production and pressure are not acceptable [i.e. gas flow volume down and pressure down based upon qualitative assessment], the mechanical swab tool is physically released from the catcher to the well.**
- **The well is then next inspected one or two days in the future. The inferred reasoning on this lapse in time frame is that the tender has previous empirical experience indicating that is the approximate time it takes for the tool to make a 'run' [i.e. return to the surface with fluid] in that the mechanical tool must drop completely through the accumulated fluid column to the well stand to set the tool/ close the mechanical valve before it can initiate a run. This presupposes that the fluid column is sufficiently short and the behind mechanical tool pressure sufficiently great to lift both mechanical tool and column of fluid to the surface for processing.**
- **If/ when the mechanical swab tool does not return to the surface the base interpretation and common empirical experience indicates that this is due to the fact that the pressure behind the tool is insufficient to lift tool and fluid column atop the tool.**

- Follow up actions to retrieve a stalled mechanical swab tool can vary and usually evolve from the simplest response of "shutting in" the well to build down hole pressure for 0.5 to 1.0 day [s] with subsequent release of the pressure rapidly directly to the brine tank. More involved and evolved actions can include the addition of a surfactant, shut in of well to build pressure and subsequent purge to brine tank to the more complex action of tool retrieval techniques using other mechanical equipment and tools.
- This non regular purging of the well of the fluids and often long periods of low to no gas flow resultant from stalled mechanical swab tools is referenced to periodically lead to down stream effects such as winter icing of the process unit further reducing gas output from the well.
- The well tenders' summary of operation of wells with mechanical casing swabs is that it tends to produce gas from the well in an uneven and punctuated manner. There are further frequent periods of well down time leading to less overall gas production than the well is capable of were the brine uniformly and regularly removed.

5.3 Project Schedule

Task Performed	[2001] Months [2002] [06/01]-07-08-09-10-11-12-[01/02]-04-06-08-10
Design Tool	>>>>>>>xxxxx C
Construct Prototype	>>>>>>xxxxxxxxxxxxxx C
Select Candidate Well [test]	>>>>>xxxxxxxxxxxxxxxxxC
Bench Test Tool	>----------xxxxxxxxxC
Test Well Production	>>>>>>>>>xxxxxxxxxxxxC
Evaluation of Performance	>>>>>>>>>>>xxxxxxC
Evaluate/ Estimate/ Recommend	>>>>xxxxxxC

Key: >>>> -Original scheduled time frame
xxxx -Revised time frame to complete
C -Completed task

6.0 EVALUATE ECONOMICS

6.1 Potential economic payback from the use of the GOAL PetroPump is estimated below from results of predecessor tool production increases in the LRI # 52 well. This data used in the base calculations was derived from operations in 2001 and early 2002. As noted above in section 5.4, redeployment of the predecessor tool in well # 52 has improved production in the month of September and October 2002 to an average of 17.5 mcf/d. As such all values noted below for payback and increases of production could be projected to improve by 15 to 20%.

6.2 Estimates of Payback from Production

Assumptions: * "Tool" Cost and Well Modifications @ $8950.00
* LRI # 52 Monthly Average Production with Tubing @ 98 mcf
* LRI # 52 Monthly Average Production with 'casing plunger' @ 252 mcf
- Value of gas @ $3.00 mcf

Table 6-2

Ave. Prod. using GOAL Pump	Ave. Prod. using tubing in 1995	Average Prod. Using 'casing plunger'	Payback @ $3 mcf vs tubing production	Payback @ $3 mcf vs 'casing plunger production
381 mcf [5 mo.]	98 mcf	252 mcf	~10 months	~25 months

Note: Average production for September and October of 2002 for this well using the GOAL PetroPump were averaging 17.5mcf/d or ~ 500 mcf/ month

It must be noted that the yields of the well tested is very small [~3 mcf/day of gas via tubing at initiation of test] in comparison to the average gas stripper well in the US @ 15 mcf/ day. These wells, even with the improvements yielded by the G.O.A.L Petropump are at or below the average US gas stripper well production. Application of the Tool in wells with greater production potential [i.e. the average stripper well] which have need for regular automatic brine [fluids] removal should yield better results and quicker payback on capital invested in the tool. The current cost of the Tool at approximately $9000 complete with wellhead modifications for installation is elevated. This is due to proprietary construction materials and techniques. Production of Tool in a commercial manner should reduce cost and payback on capital investment for the Tool user. Finally the uniqueness of the G.O.A.L PetroPump and its on Tool self-actuating controls to regulated frequency and volume of fluid removal from wells differs greatly from casing plungers producing superior results in these test and has its own unique market niche.

6.3 Cost Comparisons to Other Alternatives

Cost comparison of the G.O.A.L. PetroPump to the common used equipment for fluid removal from gas wells in the depth range of 3000' to 6000' would include:

- Pump Jack/ Beam Lift, associated sucker rod, tubing and down hole pump can have capital cost in the range of $10,000 - $40,000. Operating cost for pump jacks range from $2000 to $10,000/ year depending on volume and type of fluids produced, maintenance, replacement parts and service required.

- Tubing string production could have $8,500 to $15,000 capital cost dependant on tubing diameter and operating cost ranging in the $1500- $3000/ year for manpower & surfactants.

- **Casing plungers' capital cost with the necessary well head modifications to receive the unit are in the range of $3500 to $5000 capital. Additional capital cost for well head controllers for any attempt at automation of casing plungers is also needed [as opposed to man assisted runs], at $1000 to $5000. Operating cost would include manpower at a minimum of $500 to $1000/ year to $2000- $3000/ year on manual run tools. Work over cost to retrieve drowned and or stuck tools are not herein quantified but typical rig/ day cost are $750-$1000.**

- **Tubing plungers [Rabbits] base requirements include the installation of a tubing string at $8,500 to $15,000 as noted above plus the capital cost of a Tubing plunger at $2000 without any automation to $6000 with automation [semi] controls. Operating cost are not dissimilar to casing plungers noted above at $1000 to $3000.**

Further with respect to casing plungers and tubing plungers, they do not operate in the same or similar fashion to the G.O.A.L. PetroPump with on Tool controls and down hole/ up hole smart Tool technology.

In terms of applicability of this G.O.A.L. Tool to wells in the test area of New York State. It was determined that approximately 3,523 gas wells and approximately 529 active oil wells exist in Chatauqua County, New York. Based upon our exposure to the wells in the area it is likely that 50% or more of these wells will have fluid production related problems in the life of the wells. It is further likely they will require some form of tool related technology to produce gas and or oil. Assuming the G.O.A.L. PetroPump Tool would serve 1/3 of the wells in need of tools for enhanced production some 500 to 600 wells would be candidates for the GOAL tool in Chatauqua County. Projecting those numbers to the entire state of New York production could mean more than 1500 tools for state of New York wells.
Assuming only an 8-mcf/d increase per well [in range of test increases] at $3/ mcf could yield $13,000,000 in gas value and a pay back on 1500 tools at $9000/ tool in a one year time period

6.1 Over the recent years several organizations have begun to evaluate the number of stripper gas and oil wells in the United States which exist and are troubled by water production. BEDCO's preliminary review of the number of wells for which the technology being developed may be applicable is derived from several sources. Those specifically referenced here in are:

- **National Survey – Marginal Oil and Gas Report by IOGCC [Annual]**
- **Ohio and West Virginia Survey – University of Kentucky by E. Choong**
- **New York – IOGANY Marginal Well Study sponsored by NYSERDA 2000**

6.3 Details of these survey and more specific analysis will be developed and presented in the final report post in field testing of the tool. A GRI study by Spears indicates > 200,000 stripper wells in North America producing < 25 barrels of fluid/ day. Our preliminary analysis conservatively estimates applicability for the technology too more than 50,000 water producing gas stripper wells in the US. Potential applicability for application to stripper oil wells should be evaluated by separate analysis and testing, however a very conservative estimate could be made at 40,000 oil stripper wells.

CONCLUSION

The need for and applicability of a Gas Operated Automated Lift PetroPump [A Smart Swab Tool] for removal of fluids from stripper wells remains a sound goal and desirable tool for the oil and gas wells of America and the world. Key elements of such a tool are abilities to work in varying geologic environments of pressure, depth, fluid production, in well chemistry and operating conditions. Current target wells require the tool to be readily deployable and serviceable in 4" ID wells with but minor structural changes to the well head and process units to be economically viable.

Future needs of such a Gas Operated Automated [lift] Tool will target wells with 2.5" diameter tubing and or open hole/ large diameter completion wells or open hole completions that are readily retrofit with isolation packers and continuous smaller diameter tubing than the nominal open hole diameter of 6.25".

Bench and test stand testing of varying automated valve closure assemblies and engineering calculations indicate potential operating ranges for the prototype tool at 50 to 600+ [psi] and potential fluid lift of 0.1 to 6_-+ bbl's per tool cycle. Field trials of a prototype tool have confirmed the ability to operate in the lower half of these bench-tested values.

Automated computerized well head data loggers show they can record varying location pressures at the well head and process unit as well as continuous volume of production have evolved to a point to be applicable for in field continuous recording of operating conditions of the prototype tool. This data can serve to act as basis of tool adjustment for optimum performance and to target tool components for upgrade and improvement.

Field trials of this data logger technology on a typical target well have shown both promise of results, need for modification of software formatting and beneficial results of such modifications. These results to date indicate their applicability to meet the needs of quantifying 'real time' the effectiveness and operation of such an automated gas lift tool.

Review of operations records of a regional gas producer [i.e. total yield, current yield and decline curves] in conjunction with precursor [non GOAL PetroPump] tool testing have identified a number wells which can benefit in terms of production increases from use of an automated fluid removal tool. On a national basis tens of thousands of stripper wells appear applicable for use of the technology to improve production. Production increases even if half of the predecessor and prototype tool results can amount to tens of millions of dollars worth of additional recovered energy resources at modest well head re-configuration and G.O.A.L. PetroPump cost which could be recovered with in 1 to 3 years based upon recent prototype tool test results. Tool modifications and improvements can make the tool more durable and better functioning to further increase performance and shorten pay back on capital tool investment.

Appendix 1

Table 1 - 1   Tested Well # 52

Test Period	1996/1997	2001/2002
Completion date	11-1-83	11-1-83
Formation	Medina [Grimsby/ Whirlpool]	Medina [Grimsby/ Whirlpool]
Geology	Sandstone [tight]	Sandstone [tight]
Total Depth	3,343 feet	3,343 feet
Perforations	3,127 – 3,229 feet	3,127 – 3,229 feet
Casing size	4.5”	4.5”
Production prior to test	3 mcf/d via tubing	8mcf/d w/ casing plngr. tool
Well head pressure	320 c/ 60 t psig	180 psig
Line pressure [sales]	60 psig	55 psig
Bottom Hole Temperature	97 deg. F	-----

Table 1 – 2   Candidate Test Well # 29

Test Period	2002
Completion Date	1982
Formation	Medina [Grimsby/ Whirlpool]
Geology	Sandstone [tight]
Total Depth	2390
Perforations	2299 – 2370
Casing size	4.5”
Production prior to test	~9 mcfd w/ std. casing plunger tool
Well head pressure	150 psi
Line pressure [sales]	Variable 25 to 45 psi
Bottom Hole temperature	?

Appendix 2

Attachment C in Original Proposal with Noted Modifications to Reflect Actual Expenditures by BEDCO

	Requested & Received from SWC	Proposed Cost Share by BEDCO	Expended Cost Share by BEDCO
Salaries and Wages	$16,790--	$35,143--	$155.518--
Fringe Benefits	--	--	--
Materials and Supplies	$4,700--	--	--
Equipment	$14,600--	--	--
Travel	$4,220--	$2,170--	$2170--
Publication/ Information Dissemination	--	$2,500--	$2,500--
Other direct Cost [Misc.	--	$3,250--	$3,250--
Prototype tools/ spares and modifications	$12,500-	--	--
Work over Rid/ Fitters	$5,990--	--	--
Facilities and Administration	$1,200--	$5,760--	$5,760--
Totals	$60,000-	$47,653— [44.5%]	$155,518— [73.6%]

Note: Total combined expenditures by SWC and BEDCO on the project are $215,518.00

Development of the Vortex Oil & Gas Unit for Downhole Applications

Stripper Well Consortium
Vortex Flow, LLC Technical Progress Report
Final Report

Prepared by: Jeff Boothman

December 2003

DOE Award #: DE-FC26-00NT41025
Penn State Sub-Contract # 2301- VF-DOE-1025

DISCLAIMER

Stripper Well Consortium
Vortex Flow, LLC Technical Progress Report
Final Report

Prepared by: Jeff Boothman
Report Date: December 2003

DOE Award #: DE-FC26-00NT41025
Penn State Sub-Contract # 2301-VF-DOE-1025

"Downhole Grant"

The scope of our project was divided into two main sections:
1) To test prototypes of a downhole application of the core technology in a lab environment. This included developing prototypes, fabrication and testing in a controlled lab environment. The technology is intended to better lift production from the reservoir to the surface of the well head. These tests were completed by Texas A&M University and Vortex Flow staff.
2) To test the best design, as determined by initial lab tests in a field environment, with a longer tubing string, to confirm whether lab test results would likely be transferable to a field application. These tests were also completed by Texas A&M University and Vortex Flow staff.

As a result of the lab tests, we have determined that a two port design, with chamfered inlets was the most effective design. This design is commonly referred to as the "A2" design in the attached technical reports. Lab tests conducted at Texas A&M University by graduate student Ahsan Ali and Vortex Flow staff indicated that that the "A2" design reduced pressure loss in the tubing string by approximately 15%. <u>A full technical report of this test is attached.</u>

Additional testing in a ~1,200 foot well at Texas A&M University completed by Kartik Ramachandran and Vortex Flow Staff confirmed that the "A2" tool is effective in reducing pressure loss in the tubing string and is an effective means of unloading liquids from wells. <u>A full technical report of this test is attached.</u>

Complete Technical Reports of these two tests, which cover all activities included in this grant in their entirety, are included with this report.

Report 1: <u>Masters Thesis: Investigation of Flow Modifying Tools For the Continuous Unloading of Wet Gas Wells</u> by Ahsan Ali. 103 pages.
Report 2: <u>Field Testing of Vortex Device For Wet Gas Wells</u> by Kartik Ramachandran. 18 pages.

As a result of the work from this grant, we were able to confirm a good tool design (A2) and prove efficacy in a field setting. These tests indicate that field testing of several units in operating wells would most likely be successful.

Experimental Apparatus: For initial lab testing we used a 125 foot test tubing with an inside diameter of 2.049". Full details are available on page 17 of Report 1: Masters Thesis: Investigation of Flow Modifying Tools For the Continuous Unloading of Wet Gas Wells by Ahsan Ali.

For secondary field testing we used a 1,258 foot tubing string with a diameter of 2.375". Full details are on pages 4-8 in Report 2: Field Testing of Vortex Device For Wet Gas Wells by Kartik Ramachandran

Data Reduction: Full data analysis and conclusions are available in the attached reports. The main conclusions drawn from data reduction are as follows:

1) The amount of gas required to lift liquid up the wellbore can reduced by using the Vortex Flow "A2" design of the downhole tool.
2) The pressure loss as gas and liquids travel up the tubing string can be reduced by the flow characteristics imparted by the tool. The pressure loss can be reduced by approximately 15%.
3) The tool is effective as a means of assisting in well unloading of liquids as indicated by tests completed using approximately 1,250 feet of tubing.

Hypothesis and Conclusions:

Initial Hypothesis: The Vortex Downhole tool will organize a two-phase flow. This organized flow allows for a reduction of pressure (via a reduction in the pressure lost to a disorganized flow) in the tubing string which, in turn, allows for greater reservoir optimization (higher production rates and overall recovery) and more efficient lifting of liquids.

Conclusion: The Vortex Downhole tool is effective in reducing pressure loss in a tubing string and allows for the lifting of liquids with much lower gas rates. The degree to which the tool can assist in improving these characteristics will have to be studied to build relationships that define a prescription for use of the technology.

Field Test of the Vortex Oil & Gas Unit in Gas Gathering Systems

Stripper Well Consortium
Vortex Flow, LLC Technical Progress Report
Final Report

Prepared by: Jeff Boothman

December 2003

DOE Award #: DE-FC26-00NT41025
Penn State Sub-Contract # 2278- VF-DOE-1025

DISCLAIMER

Stripper Well Consortium
Vortex Flow, LLC Technical Progress Report
Final Report

Prepared by: Jeff Boothman
Report Date: December 2003

DOE Award #: DE-FC26-00NT41025
Penn State Sub-Contract # 2278-VF-DOE-1025

"Gathering Grant"

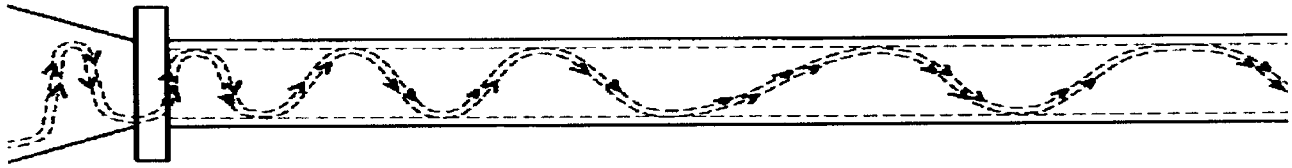
The scope of our project was to install Vortex SX tools in a gas gathering system working our way away from the delivery point of the gathering system (Amine Plant) back into the producing system. The goal of the installations was to reduce the pressure drop between points within the gathering system and to enable greater throughput when the Amine Plant is capable of greater capacity.

We installed eleven Vortex SX tools at strategic points in a gathering system owned by Cabot Oil and Gas in Wayne County, West Virginia. During the test period, we collected pressure data for all key points in the test gathering system where Vortex Flow SX tools were installed. Test data indicates that the pressure drops across points in the gathering system where Vortex SX tools are present have been very consistent and continue to be in the range of 2% to as much as 80% across a wide range of operating conditions. Data indicates that a combination of pipe size and mass flow have an effect on the magnitude of reduction in pressure drop that can be achieved by use of the tool. This effect would need to be further investigated to get a more definitive model of this effect.

Hypothesis:

The project was based on the theory that the unique flow regime created by the Vortex Flow SX tools would be able to reduce gathering line backpressure felt by all wells connected to the gathering system. It was hypothesized that by either moving accumulated fluids downstream or by improving overall flow organization, the Vortex Flow SX units would reduce backpressure felt by wells connected to the gathering system and allow for increased production. The flow created by the Vortex Flow SX units is depicted in Figure 1.

Figure 1 – Diagram of flow created by Vortex Flow SX unit.



Hypothesis – Continued: If we were successful in reducing gathering system backpressure, as measured by the pressure drop between points in the gathering system, we could effectively lower well bottom hole pressure as indicated by the changing conditions in Figures 2 and 3. Using Vogel's Inflow Performance Relationship Curve (Figure 4), we hypothesized that the reduced bottom hole pressure would result in increased production.

Figure 2 – Typical System Pressure Diagram Before Vortex Flow SX Tool Installation

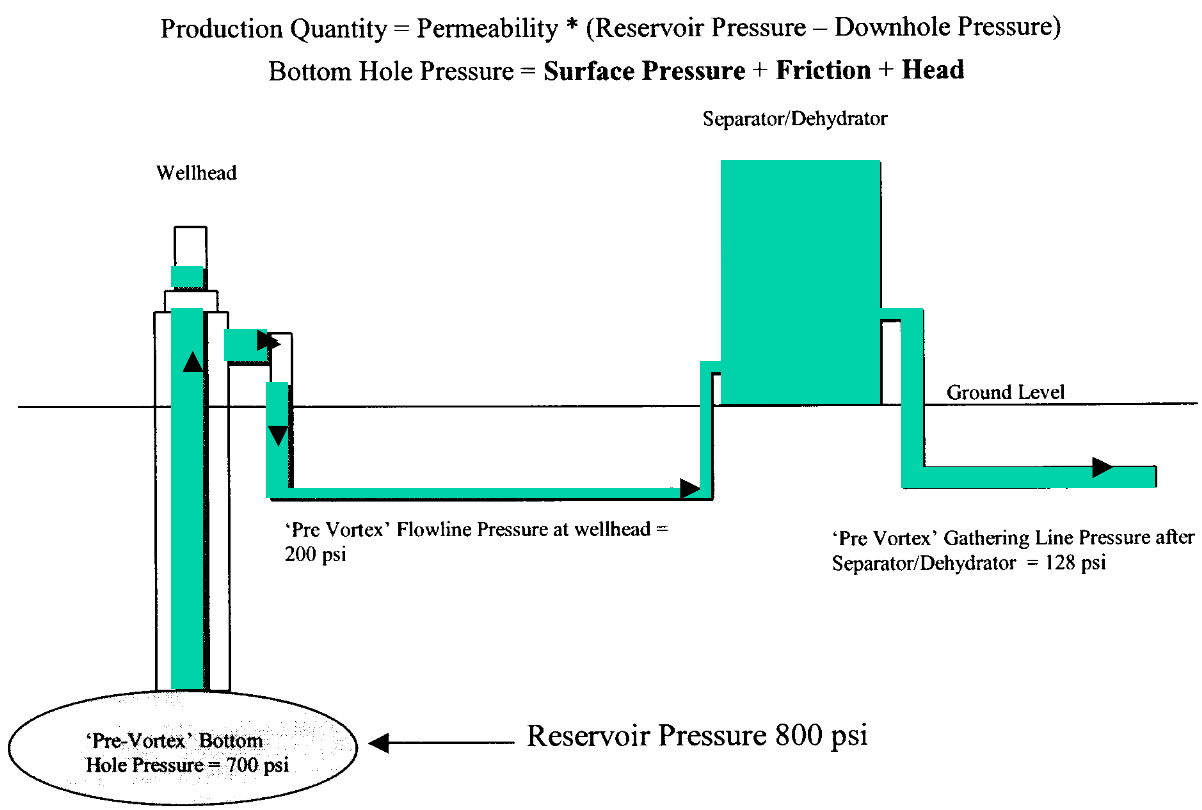


Figure 3 -Typical System Pressure Diagram After Vortex Flow SX Tool Installation

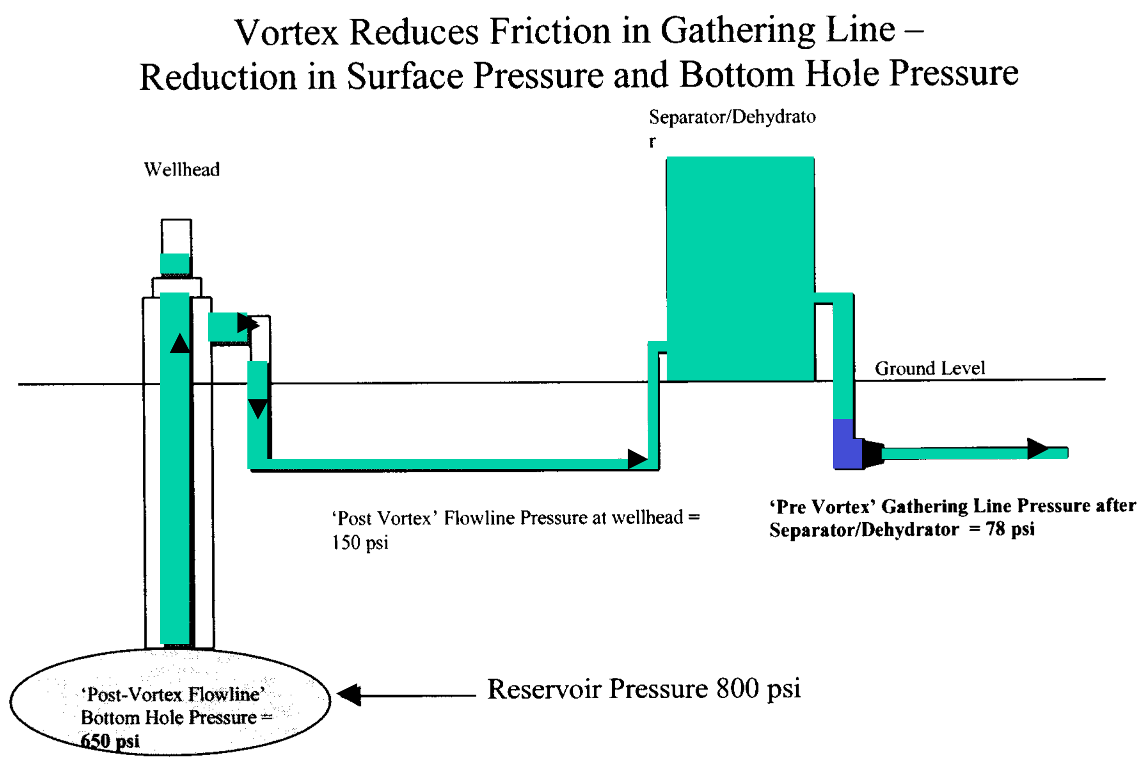
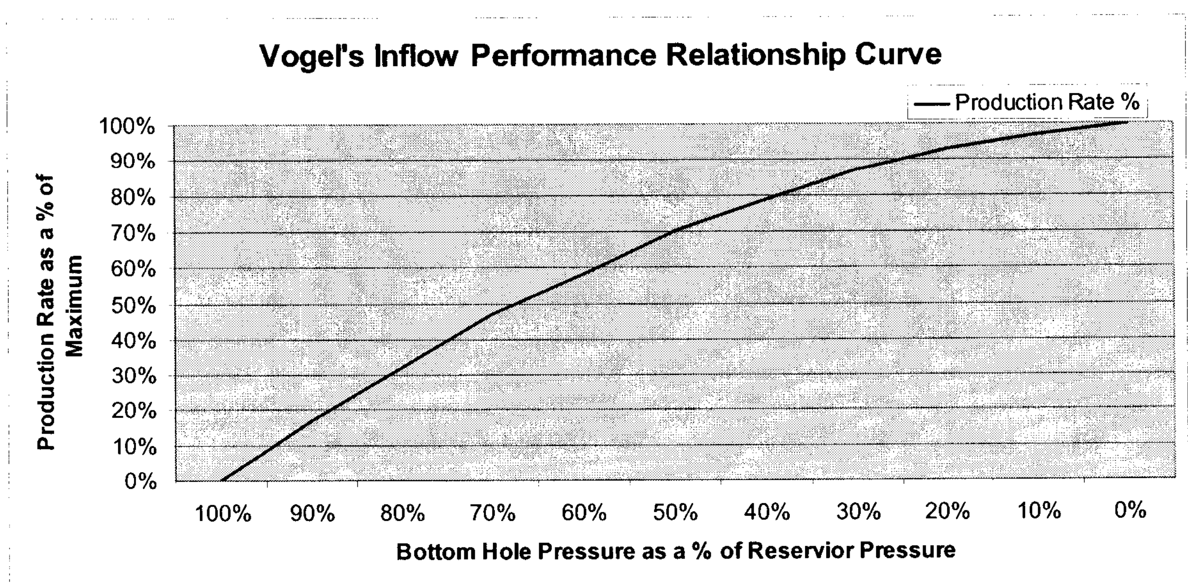


Figure 4 – Vogel's Inflow Performance Relationship Curve



Experimental Apparatus: Standard 2", 4" and 6" Vortex Flow SX units (See technical specifications below) were used in the tests. Units were installed at strategic points in the gathering system with the following general rules for tool placement:

1) Tools were placed at points just AFTER additional feeder lines entered the gathering system
2) Tools were installed at points where the flow regime created by the tool was given log run of straight pipe with no feeder lines entering the line with the tool installed for at least 1,500 feet.
3) All drips downstream of tool installations were removed.
4) Tools were put at low elevation sites in the gathering line when a choice between a low elevation installation site and a higher elevation installation site was available.

A map showing the system and all tool installation points is included with this report. A schedule of tool sizes, installation sites and distances from the collection point (Amine Plant) is included in Table 1. No liquids were observed in the gathering lines during installations. Pressure drop between points in the system and the Amine Plant have been reduced by 2% - 80% since SX tools were installed. The largest reductions in pressure drop were seen in the highest rate sections of the gathering line.

Technical Specifications – Vortex Flow SX Tools

Pipe Steel:	ANSI Schedule 40
Back Plate:	A36 Grade Steel
Weld Specification:	ASME B31.3
Tool Hydrotesting:	To 700 p.s.i or greater
Connection:	Threaded, using spools (see Photo 1)
Interior Coating:	None

Table 1 – Schedule of Installation Sites

Well / Tap	Tool Size	Flow Rate MCFD	Distance From Amine Plant (Ft)
CNR #2	4"	77	27,000
CNR #18	2"	81	27,000
Prichard A-1	4"	520	23,000
E. Piles #1	2"	125	25,000
Gypsy Wright A-3R	2"	39	20,000
Gypsy Wright A-1	4"	3	17,500
Gypsy Wright #1	4"	45	15,500
Inglehart #1	2"	45	17,500
Prichard #8	2"	57	14,000
C-619 & C-469 tie	6"	3742	13,000
Agee #1	6"	34	7,000
Amine Plant	None		0

Experimental and Operating Data: Data analysis shows a consistent reduction in pressure drop between measured points in the gathering system and the Amine Plant. Data was collected for 4 weeks before installations and for 8 weeks after installations. All reductions in pressure drops are listed in percentages. Average reduction in pressure drop was on the order of 15% +/- with wide variation as shown below:

Descriptive Statistics for Reduction in Pressure Drop

N	Mean	Median	TrMean	StDev
11	-0.1894	-0.1014	-0.1396	0.2283

Minimum	Maximum	Q1	Q3
-0.8047	-0.0224	-0.2593	-0.0483

Table 2 – Reduced Baseline and Test Data

	Pressure Difference from Installation Points to Amine Plant			
Well / Tap	**Week Pre-Installation Ave.**	**8 Weeks Later**	**% Change in Pressure Drop**	**% Change in Pressure Drop**
CNR #2	**78.00**	76.25	(1.75)	**-2.24%**
CNR #18	**72.00**	68.00	(4.00)	**-5.56%**
Prichard A-1	**69.67**	53.00	(16.67)	**-23.92%**
E. Piles #1	**56.67**	55.25	(1.42)	**-2.50%**
Gypsy Wright A-3R	**37.00**	33.25	(3.75)	**-10.14%**
Gypsy Wright A-1	**36.33**	34.00	(2.33)	**-6.42%**
Gypsy Wright #1	**37.67**	32.25	(5.42)	**-14.38%**
Inglehart #1	**39.67**	37.75	(1.92)	**-4.83%**
Prichard #8	**27.00**	20.00	(7.00)	**-25.93%**
C-619 & C-469 tie	**35.83**	7.00	(28.83)	**-80.47%**
Agee #1	**16.17**	11.00	(5.17)	**-31.96%**
Amine Plant	**-**	-	-	
Ave.	**46.00**	38.89	(7.11)	**-18.94%**

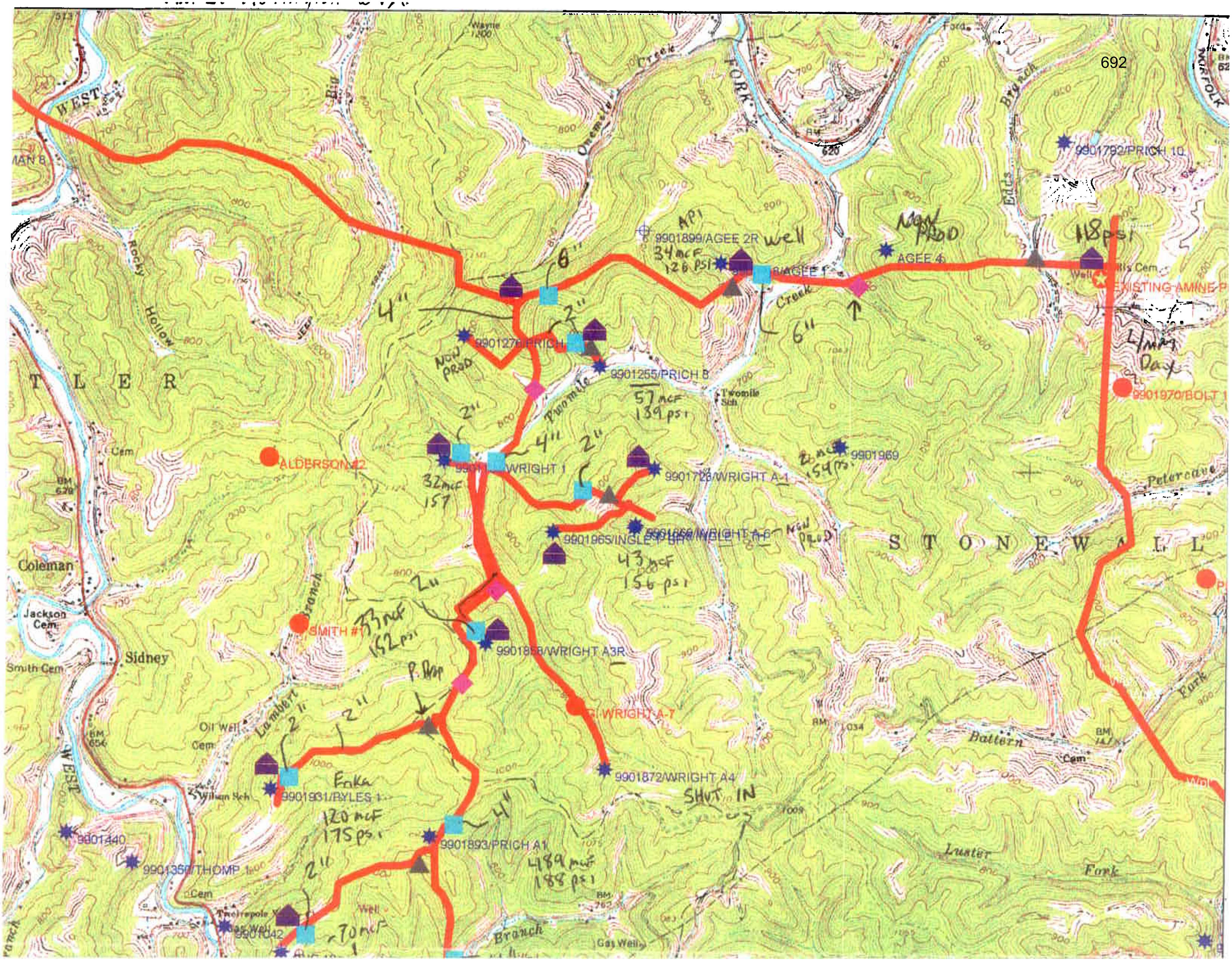
Hypothesis and Conclusions: Our initial conclusion is that the Vortex SX units have the ability to help gathering systems reduce pressure drop across all points in the system by both organizing the flow within the gathering line and by ensuring that accumulated fluids are swept downstream to points in the system where they can be properly collected. Use of the tools will lower total system pressure and will allow wells attached to the gathering system <u>with good pressure response</u> to realize additional production as the efficiency of the gathering system is improved.

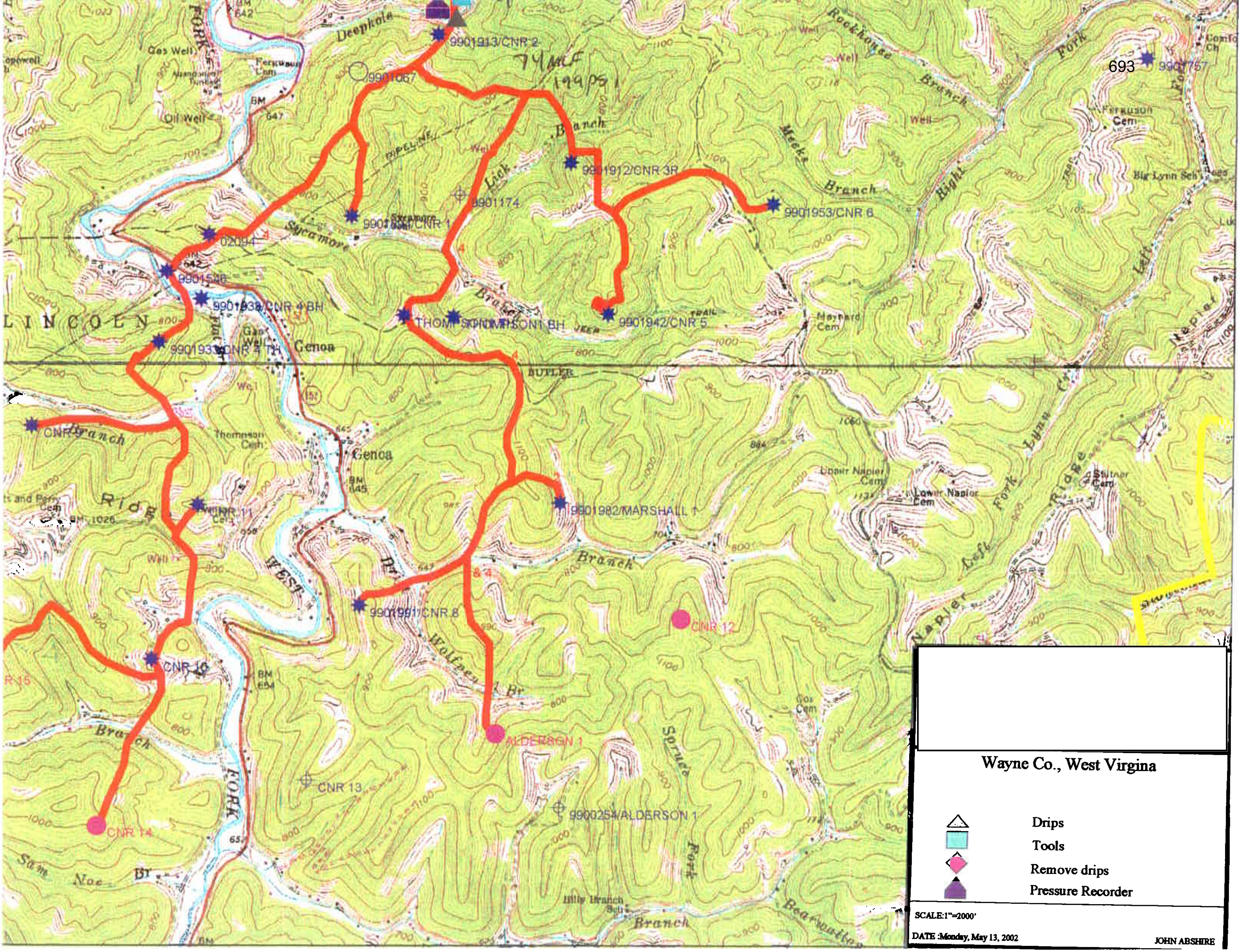
In our tests, we did see a reduction in pressure drop (alternatively – improved system efficiency) but did NOT see increased production as the producing formation was very tight and did not have characteristics that would allow for a good production response to lower pressures.

From these tests, we have confirmed the need for good field pressure response if a key objective of tool use is to improve production. The tools are effective in lowering line pressures and moving fluids if the objective of tool use is to increase throughput or move fluids through the system.

It also appears that there is a relationship between mass flow rates and the associated reduction in pressure drop found at various points in the test system. This effects would have to be further investigated to better define and understand if this effect is repeatable and statistically significant and predictable.

Photo 1. 4" Tool installation with spool


9901899/AGEE 2R
API well
34 mcf
126 psi
AGEE 4
Non PROD
118 psi
9901792/PRICH 10
EXISTING AMINE P
9901970/BOLT 1
6"
4"
2"
9901276/PRICH
Non PROD
9901255/PRICH 8
57 mcf
139 psi
ALDERSON #2
WRIGHT 1
32 mcf
157
9901728/WRIGHT A-1
9901969
9901965/INGLE
New PROD
43 mcf
156 psi
SMITH #1
33 mcf
152 psi
9901858/WRIGHT A3R
P. Prod
C. WRIGHT A-7
9901872/WRIGHT A4
SHUT IN
9901931/BYLES 1
120 mcf
175 psi
9901440
9901350/THOMP 1
9901893/PRICH A1
489 mcf
188 psi
9901042
70 mcf
S T O N E W A L L
T L E R
Coleman
Sidney
Jackson Cem
Smith Cem
Twomile
Twomile Sch
Rocky
Hollow
Big
Onemile
Creek
FORK
WEST
Lambert
Branch
Oil Well
Wilson Sch
Twelvepole
Gas Well
Peter cave
Battern
Luster
Fork
Edds
Branch
NORFOLK


Wayne Co., West Virginia
Drips
Tools
Remove drips
Pressure Recorder
SCALE:1"=2000'
DATE :Monday, May 13, 2002
JOHN ABSHIRE
9901913/CNR 2
9901067
9901912/CNR 3R
9901953/CNR 6
9901174
9901942/CNR 5
9901982/MARSHALL 1
CNR 12
ALDERSON 1
CNR 13
9900254/ALDERSON 1
CNR 10
CNR 14
9901757
693
74 MCF
199 PSI
Deephole
Genoa
BUTLER
LINCOLN

Field Test of the Vortex Oil & Gas Unit in Stripper Well Flowlines

Stripper Well Consortium
Vortex Flow, LLC Technical Progress Report
Final Report

Prepared by: Jeff Boothman

December 2003

DOE Award #: DE-FC26-00NT41025
Penn State Sub-Contract # 2279- VF-DOE-1025

DISCLAIMER

Stripper Well Consortium
Vortex Flow, LLC Technical Progress Report
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Penn State Sub-Contract # 2279-VF-DOE-1025

"Flowline Grant"

Overview: The scope of our project was to install nineteen of Vortex SX tools in the well flowlines in operating wells in the Michigan and Appalachian basins in order to determine if the tools could assist in reducing flowline backpressure and increase realized production. All wells included in the trials were owned and operated by Belden and Blake.

We installed twelve Vortex SX tools in wells in the Michigan Basin. All installations were made at a point just after the wellhead and at the beginning of a pipe run to the water separator. Since individual well measurements were NOT available, the tools were installed in all wells in a well "pod" for which production data (including historical data) was available.

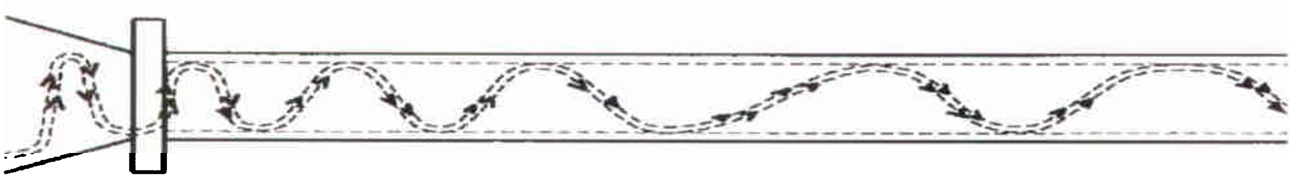
Additionally, seven units were installed at wells in the Appalachian Basin using the same basic positioning of the tool in the flowline. (an additional three units, not paid for by grant monies, were included in the data collection and reduction).

After installation, actual production was measured and compared to agreed decline curves to determine if a statistically significant increase could be found. Other related anecdotal data such as increased water flow or lower flowline pressures (where they could be measured) were also captured.

Hypothesis:

The project was based on the theory that the unique flow regime created by the Vortex Flow SX tools would be able to reduce flow line backpressure felt by the well by either moving accumulated fluids downstream or by improving overall flow organization. The flow created by the Vortex Flow SX units is depicted in Figure 1.

Figure 1 – Diagram of flow created by Vortex Flow SX unit.



Hypothesis – Continued: If we were successful in reducing flow line backpressure, we could effectively lower well bottom hole pressure as indicated by the changing conditions in Figures 2 and 3. Using Vogel's Inflow Performance Relationship Curve (Figure 4), we hypothesized that the reduced bottom hole pressure would result in increased production.

Figure 2 – Typical System Pressure Diagram Before Vortex Flow SX Tool Installation

Production Quantity = Permeability * (Reservoir Pressure – Downhole Pressure)

Bottom Hole Pressure = **Surface Pressure** + **Friction** + **Head**

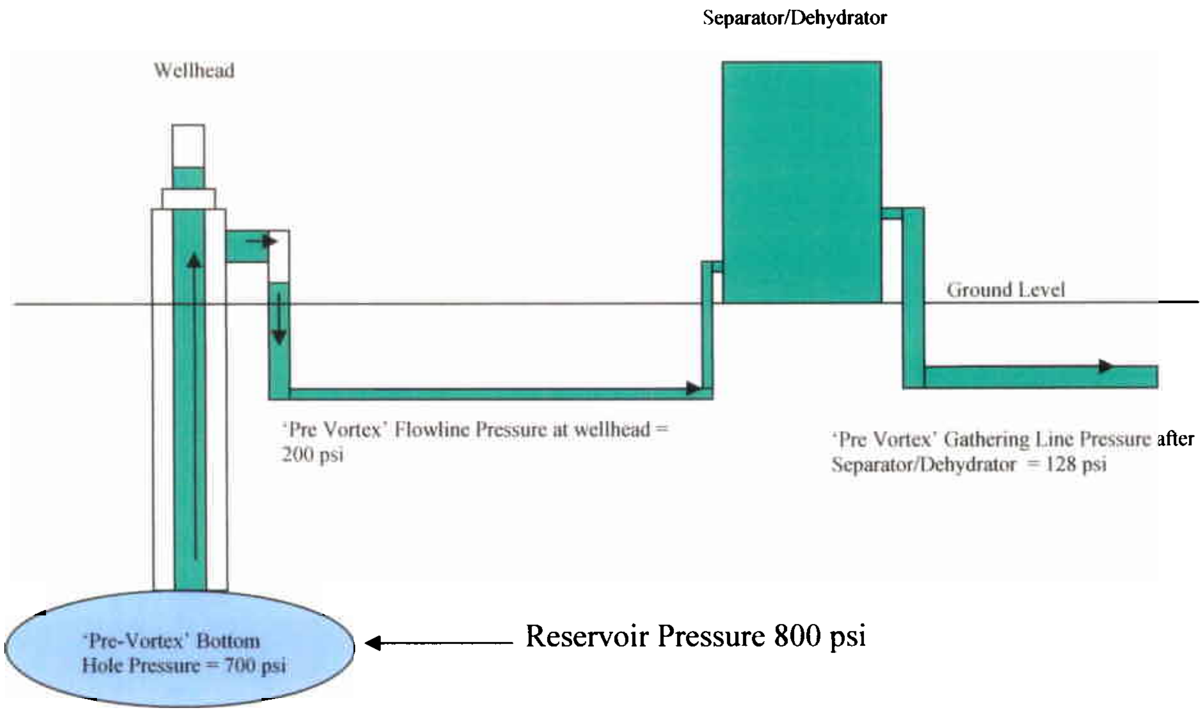


Figure 3 -Typical System Pressure Diagram After Vortex Flow SX Tool Installation

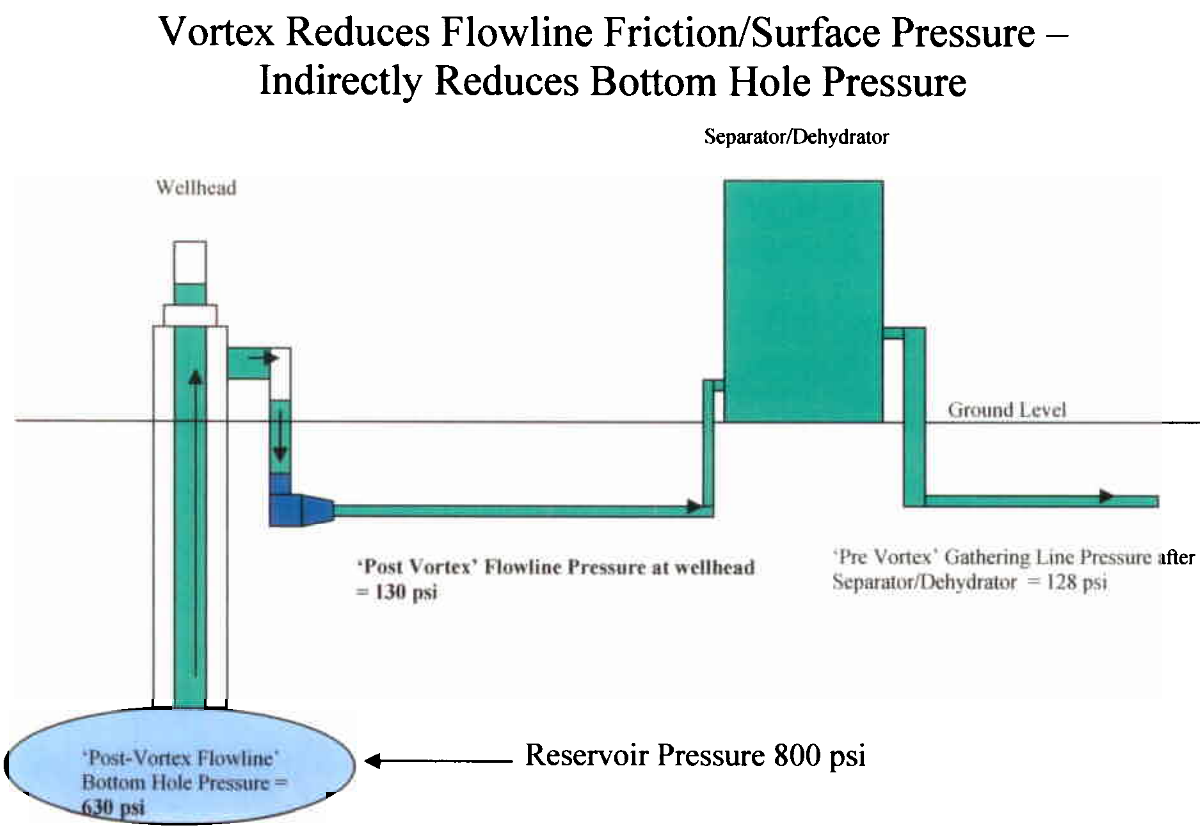
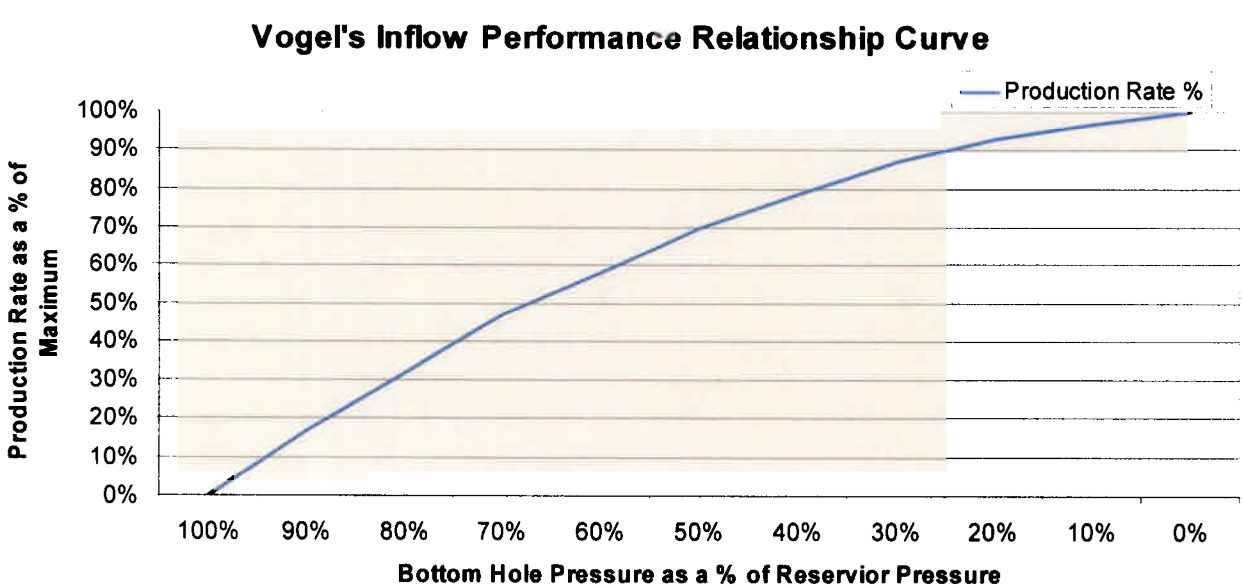


Figure 4 – Vogel's Inflow Performance Relationship Curve



Experimental Apparatus: Standard Vortex 2", 2 ½" and 3" SX units were used in the tests. All of the units were installed within 20 feet of the wellhead at a point just after the wellhead on the run to the water separator (or pod water separator). Additional well information and tool technical specifications are included below.

General Well Specifications:

Basin	**Operating Pressures**	**Production**
Appalachian	50 – 15- p.s.i.	10 – 125 MCFD
Michigan	1 – 15 p.s.i.	50 – 80 MCFD

Michigan Basin Well Information:

Basin:	Michigan
Formation Type:	Antrim Shale
Well Age:	5 years +
Well Type:	Rod Pump
Flowline Size:	2"
Flowline Length:	500 feet to 8,000 feet - depending on well
Vortex VX Install:	At surface just after wellhead

Appalachian Basin Well Information:

Basin:	Appalachian
Well Age:	2 to 7 years
Well Type:	Flowing
Flowline Size:	2", 2 1/2" and 3"
Flowline Length:	500 feet to 2,000 feet - depending on well
Vortex VX Install:	At surface just after wellhead

Technical Specifications – Vortex Flow SX Tools

Pipe Steel:	ANSI Schedule 40
Back Plate:	A36 Grade Steel
Weld Specification:	ASME B31.3
Tool Hydrotesting:	To 700 p.s.i or greater
Connection:	Threaded
Interior Coating:	None

Michigan Basin Installations:

The Vortex SX units were installed on the wells in late July, 2002. Each installation took approximately 2 hours. In the subject wells, a rod pump is used to pump water up the tubing while gas is flowed up the casing and then fed in to gas flowlines. Operating pressures for the wells are generally in the range of 6 p.s.i. to 12 p.s.i. with some wells having pressures as low as 1-2 p.s.i.

A significant problem for this system was the "falling out" of water entrained in the gas stream during periods of large temperature swings (primarily fall and spring months). The water that drops out of the gas stream was collecting in the flowlines increasing back pressure and making the system prone to frequents freeze-ups in the very cold Northern Michigan environment.

Appalachian Basin Installations

The Vortex SX units were installed on the wells in late July, 2002. Each installation took approximately 1-2 hours. All wells that received the tools were flowing wells. In all cases the tools were installed in wells that had flow lines that ran directly to a separator or collection point. However, there were several tools that were installed on flow lines that also received production from an additional 1-2 wells upstream in the system along with production from the well on which the tool was installed. We did see improvements in production for wells connected to those that had tools installed but these improvements were not included in the data measurement and reduction.

Experimental and Operating Data:

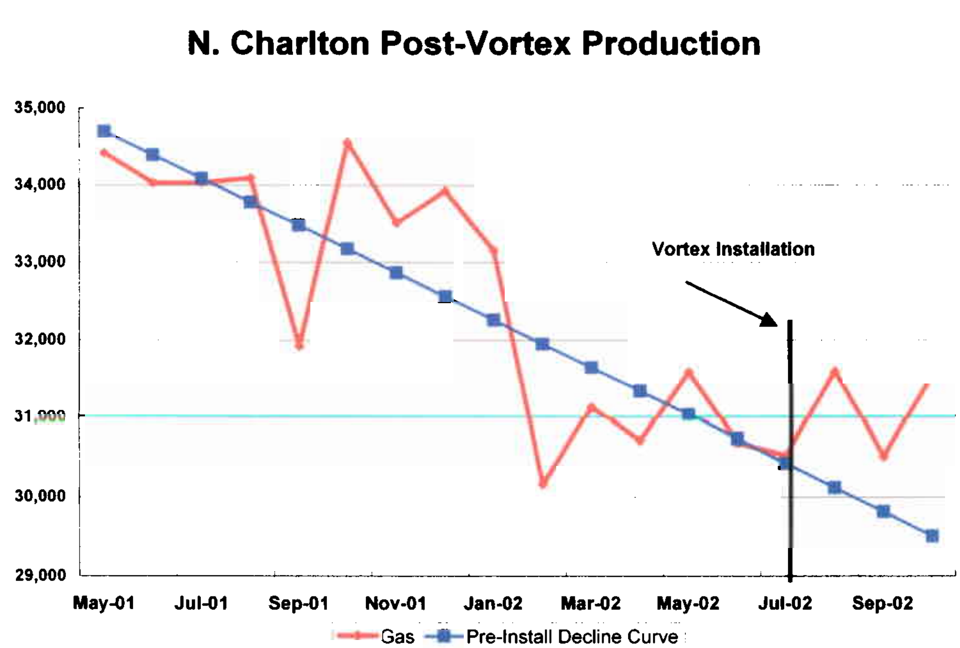
Data Analysis Methodology

1) All 10 wells in the Appalachian Basin test were analyzed individually
2) All 12 wells in the Michigan Basin test pod were analyzed as a single data stream as individual well data was not available.
3) Pre-Installation production data was gathered back to 1996 or when the well went online, whichever was later.
4) Using Actual production data, decline curves were generated and agreed.
5) Agreed decline curves were used as the baseline to measure whether the tools generated any production improvements
6) Five months of post installation data was collected, aggregated and compared to the five month total expected production predicted by the decline curves

Test Results

Data analysis showed a very modest increase in production for the lower pressure Michigan Basin wells (see Figure 5) . A production increase of approximately 5% over the long-term decline curve was noted. There were some small increases in produced water but it was agreed that this was most likely due to movement of some of the water trapped in the flowline to the separator.

Figure 5 – Results From Michigan Basin Vortex SX Installations



Test Results - Continued

In the Appalachian Basin wells, the success rate was much more significant. Table 1 shows the actual and expected production for the 10 wells in the test. In general, production was flat to up as much as 48%. Figures 6 and 7 show the same data in a different method. Figure 6 shows actual pre-installation production as a percentage above or below the decline curve. All data points below 0% indicate production below the decline curve and all data points above 0% indicate production above the decline curve. Figure 7 shows the results from all test wells after the Vortex Flow SX installations.

Table 1 – Results from Vortex Flow SX Tool Installations in the Appalachian Basin

Well Name	Pre Install MCFM	Pre Install MCFD	5 Month Total Predicted by Decline Curve MCF	Actual Production MCF	Difference MCF	Difference
ROGGENKAMP #1	562	18	3,208	3,261	53	1.65%
MCCHESNEY #1	1,792	59	8,873	10,980	2,107	23.75%
COZY #1	396	13	2,075	2,371	296	14.27%
BEAGLE CLUB #1	578	19	2,759	3,585	826	29.93%
MERKLE #1	2,148	71	4,823	5,501	678	14.06%
CHERRY RUN #2	3,792	125	11,503	12,773	1,270	11.04%
GOODWILL #2	2,326	77	6,353	8,542	2,189	34.46%
SEAMANS #1	3,086	102	6,600	9,774	3,174	48.09%
HEATH #2	1,544	51	6,005	6,890	885	14.74%
GOODWILL #3	2,792	92	10,766	11,029	263	2.44%

Figure 6 – Actual Production as a % Over or Under the Agreed Decline Curve

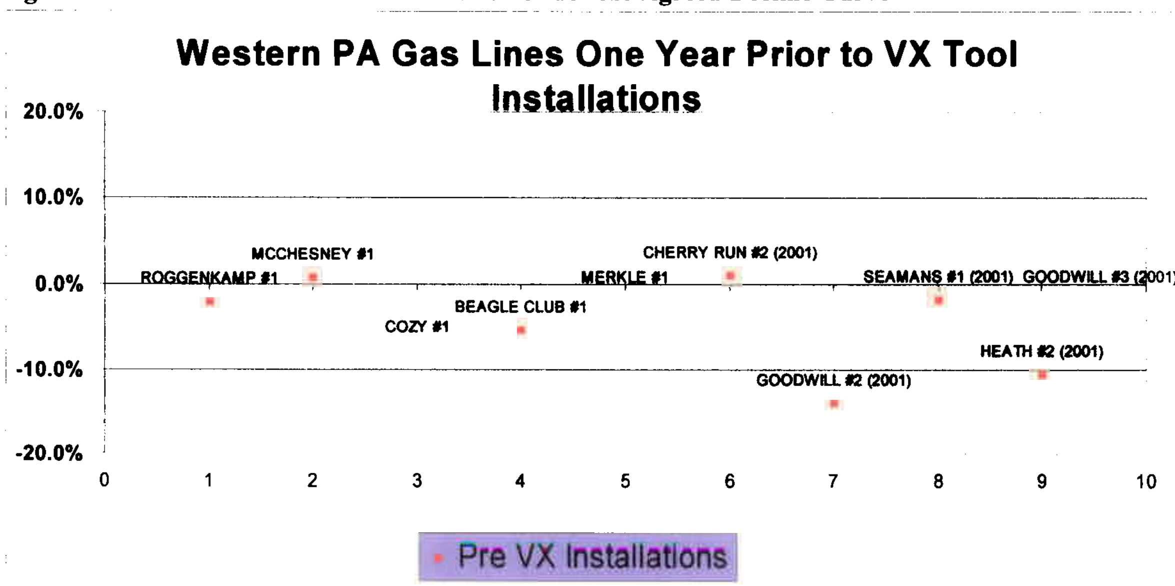
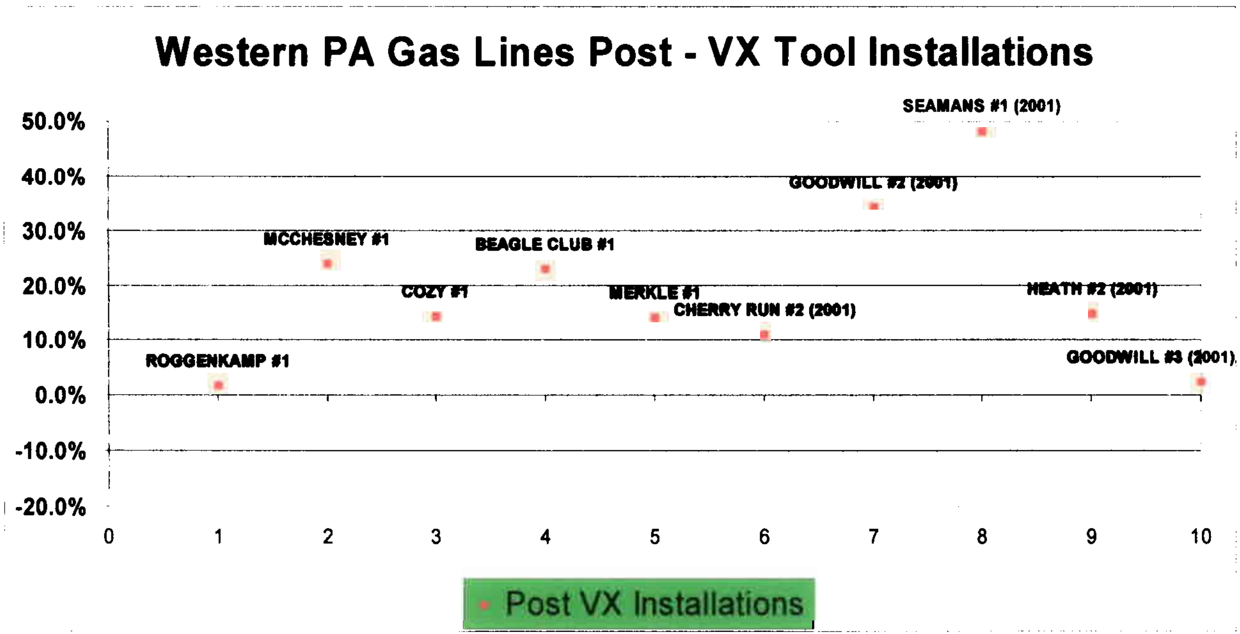


Figure 7 – Actual Production as a % Over or Under the Agreed Decline Curve



Hypothesis and Conclusions: We have drawn the following conclusions based on the results from the tests covered by this grant:

1) The Vortex SX units have the ability to help organize flows in flowlines to making the flow regime more efficient and reducing backpressure experienced by the well. The benefit from this effect varies based on operating pressures.
2) The lower bound operating pressure (or mass flow rate) for the Vortex SX tool to be effective is somewhere above the pressure/flow conditions seen in the Michigan Basin installations. Additionally, formation permeability may also play a role in whether small pressure reductions achieved through use of the technology could be used to increase production and recoverable reserves.
3) The Vortex SX tools are very effective as a tool for increasing production for wells that have higher operating pressures and higher mass flow rates. The tools are a good solution for increasing both production and recoverable reserves by lowering flowline backpressure in these types of installations.

Field Testing of New Technologies for Lifting Liquids from Gas Wells

Final Report

December 1, 2002

to

December 31, 2003

by

Richard L. Christiansen

February 2004

DOE Award Number DE-FC26-00NT41025

Petroleum Engineering Department
Colorado School of Mines
Golden, CO 80401-1887
U.S.A

Disclaimer

Abstract

When initially completed, many natural gas wells are capable of lifting liquids to the surface. But, with depletion of the reservoir pressure, there comes a time when liquids can no longer be lifted to the surface and they begin to accumulate in the bottom of the well, dramatically inhibiting or stopping gas production. The cause of diminished liquid-lifting ability is the decline of liquid droplet production at gas flow rates below the Turner-Hubbard-Dukler critical velocity.

In a previous project supported by SWC, devices for stimulating droplet production were studied with bench-top and flow-loop testing. Listed below are the two proposed tasks for this stage of the project.

Task 1: Field testing of new technologies. Using results of the previous SWC project, proceed to field testing of the most promising technologies. Choose a suitable business partner for these tests. Continue tests in the flow loop as needed to support field tests.

Task 2: Integrated modeling of gas well production. Continue to develop numerical models that combine the complexities of two-phase flow in the wells and the adjacent reservoir with the droplet-stimulation technologies. Use these models to design and interpret field tests.

Accomplishments for each of these tasks are summarized below.

Task 1: Field testing of new technologies. Vibrational, rotational, and two-fluid devices were tested in the previous project. In flow loop tests, the rotational device failed to provide droplets for transport. The two-fluid devices were more promising, but most of the droplets impinged on the walls of the 2.5-inch-ID tubing. These devices might be more applicable for application in large diameter tubing or casing. The vibrational devices provided very small droplets that were easily transported in the flow loop. We chose to focus efforts on developing vibrational devices for field testing.

Two prototypes were assembled and tested in the flow loop. Each prototype consisted of a 2-MHz ultrasonic transducer inside of a cylindrical PVC housing. The OD of the housing is 2.13 inches. This is the smallest diameter that could accommodate the transducer. This device was suitable for testing in the flow loop but was not robust enough for field testing. As anticipated, difficulties with protecting the electronics from water were encountered. Two approaches were designed for dealing with water. One was tested in the flow loop.

The prototypes also lacked a water sensor for preventing "burning" of the piezo-electric disk of the transducer. Suitable sensor technology was identified but not tested.

In the prototypes, a four-wire cable was used to provide the 48 volt power to the transducers. For field testing, such a cable would not be sufficient.

Task 2: Integrated modeling of gas well production. We continued simulation of the reservoir-well system with Eclipse 100 models. The models used in these simulations consisted of a single well and adjacent productive formations. The performance of the well was included in a very approximate manner – improving the representation of the well in such simulations is a challenge. Models for wells with and without hydraulic fractures were used. A wide range of reservoir permeabilities and relative permeabilities were studied. The results of these simulations show that incomplete removal of water from wells can diminish ultimate gas recovery by as much as 20%, depending on the properties of the reservoir. To avoid these losses of recovery, contact of the producing formation with liquid water in the well must be minimized.

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Description of Approaches

Task I: Field testing of new technologies. In the first phase of this project sponsored by SWC, we studied production of droplets by three approaches: vibrational, rotational, and two-fluid devices (Christiansen, 2003). All three approaches produced sufficiently small droplets in bench-top tests. The bench-top tests also demonstrated well-documented features of these three approaches: rotational and two-fluid devices impart a significant velocity to the produced droplets, while the vibrational devices produce low velocity droplets. The importance of these features was very apparent during tests in the flow loop. Droplets from the rotational device impinged almost immediately on the walls of the tubing. The two-fluid devices were more promising, yet about 70% of the droplets impinged on the walls. Most if not all of the droplets produced by the vibrational devices were lifted to the top of the 40-foot flow loop. As a result, we eliminated rotational devices from further consideration. We speculated that two-fluid devices might find application for droplet generation in larger diameter tubing or casing. And we chose to focus efforts for the second phase of the project on vibrational devices.

In this second phase of the SWC project, we developed two prototypes of vibrational devices for converting bulk liquid into very small droplets in a gas well. Both of these prototypes were designed to use a commercially available ultrasonic transducer that is manufactured by TDK. Figure 1 shows the mist production rate for the TDK transducer as a function of temperature.

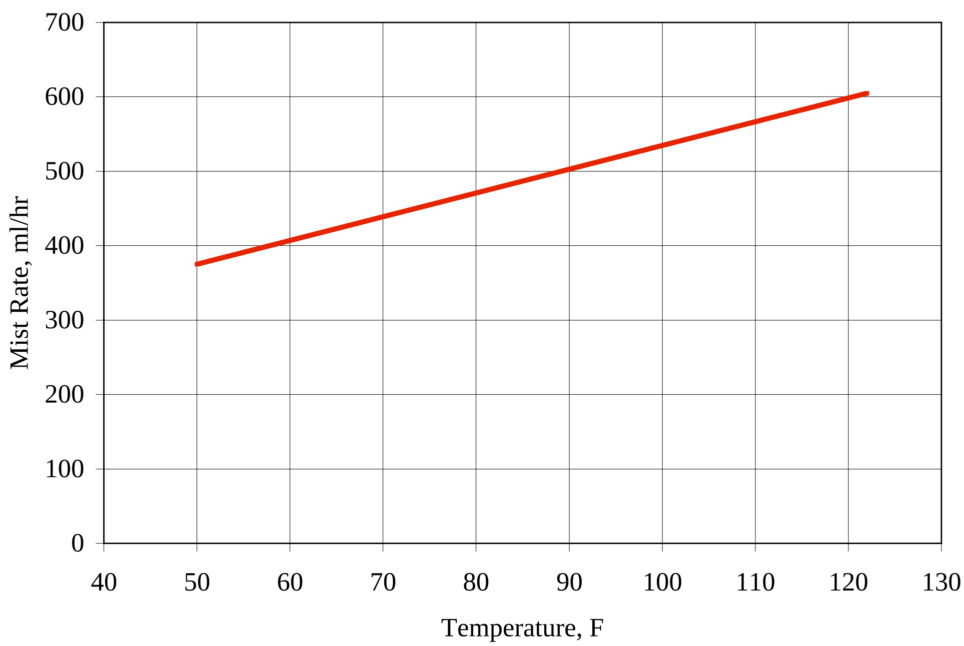

Figure 1. Mist production rate for TDK transducer.

TDK is the only manufacturer of transducers that provides technical description of their product. The upper limit for operation of the TDK transducers is 140˚F, so the application of these transducers is limited to wells with bottom-hole temperatures less than 140˚F. As there are many gas wells in this category, this limitation is not a near-term issue. The rate of mist production for the TDK transducer is about 600 ml/hr at 120˚F. This corresponds to about 0.1 bbl of water per day. Clearly, more than one transducer would be needed for most gas wells. But for demonstration of the concept of mist production with a vibrational device, the TDK transducer is the best choice. Mist production rates for other readily available devices are about 50% of the TDK rates.

Sketches of the two prototypes are shown in Figure 2. These prototypes consist of 2" clear PVC pipe with end-caps, supports for the piezo-electric (PZ) disk, chambers for the TDK electronics, and aluminum heat sinks, and windows to allow liquid to accumulate above the PZ disk assembly.

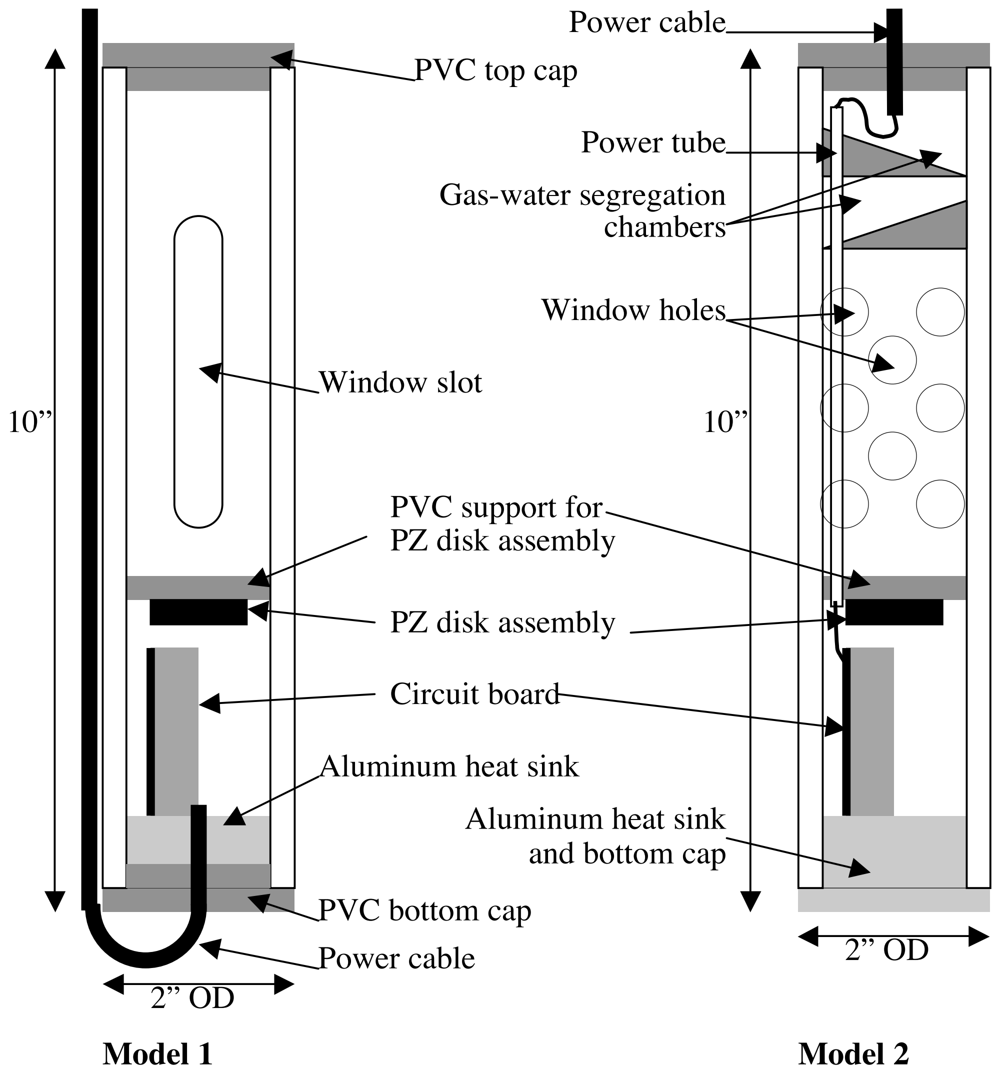

Figure 2. Two prototypes for vibrational devices.

The two prototypes share many features, but differ in some important aspects. In Model 1, the power cable passes by the side of the device and enters through the bottom cap. During vigorous flow testing of this model, water entered the electronics chamber and caused it to fail.

The water probably entered through the seals on the PZ disk assembly during pressure surges. This problem was anticipated because the PZ disk assembly was not designed to support large pressure differences. To eliminate this problem in Model 2, the power cable enters through the top cap, and the power wires travel down the power tube to the electronics chamber. Gas can also pass through the power tube, which allows pressure equilibration between the gas outside of the electronics chamber and the gas inside the chamber. Thus, the pressure is balanced across the PZ disk. The power tube allows equilibration of pressure, but it could also allow water entry to the electronics chamber. To prevent that, two chambers were provided for water to segregate from gas.

Dispersion of heat from the power transistor on the TDK electronics was another concern. In Model 1, the circuit board was attached to an aluminum heat sink that rested against the bottom cap, also made of aluminum; however, this approach did not effectively reject heat to the outside flow. So in Model 2, the function of the heat sink was combined in one piece with the bottom cap, greatly increasing the heat rejection capacity. This approach also simplified assembly of the prototype.

Two different designs of windows for collecting liquid and expelling mist were tested in the two models. In Model 1, two long slots were cut into opposite sides of the 2" PVC pipe. In Model 2, an array of circular holes was cut.

According to TDK specifications, the PZ disk should be submerged in about 40 mm of water for proper operation. If water level falls too low, then the PZ disk overheats and fails. To prevent this fatal condition, a water-level sensor is needed. Neither of the prototypes has a water-level sensor because I do not know how to integrate a sensor with the TDK transducer. The absence of a water-level sensor is an inconvenience for testing of these prototypes, but testing could proceed as long as great care is exercised to maintain sufficient water level above the PZ disks. Water-level sensors are absolutely necessary for field testing. Inclusion of those sensors in a field-suitable device will have to wait for a future project.

I would very much have liked to build prototypes with smaller outside diameters. Indeed, some preliminary designs were sketched. But those designs required custom electronic circuit boards and were eliminated from further consideration. Models 1 and 2 have about the smallest possible diameters for using the TDK transducer. Indeed, I had to remove the heat sink provided by TDK and shave almost 1/16" off the width of the TDK circuit board to allow it to fit in the 2" pipe. With more resources to develop custom electronics, prototypes with diameters of 1.0 to 1.4 inches are very possible. But as is often the case with research such as this that explores the fringes of what is possible, compromises are needed to make progress.

After constructing the models, they were first tested on the bench and then in the flow loop. The lay-out of the flow loop is shown in Figure 3. The prototypes were suspended by the power cable, 2 to 3 feet above the bottom of the flow loop. Prior to a test, the horizontal pipe at the bottom of the flow loop was filled partially with water. During a test, air flowing through the horizontal section blew water onto the prototypes. The rate of collection of water above the PZ disk inside the prototypes was noted. Flow rate of air was varied to assess transport of droplets. In all tests, transport of droplets was detected by scattering of light from a He-Ne laser beam and by collection of water in the gas-liquid cyclone separator.

Tests in the flow loop were done in a vertical 4-inch-ID PVC tube. This larger diameter was needed to accommodate the OD of the prototypes. The prototypes would fit inside a 2.5-inch-ID tube, but the close fit would not allow for any significant gas flow rate. Furthermore, if the misting approach actually proves viable, it would make sense to pull tubing and produce through casing whenever possible. That would minimize pressure drop and increase productivity of wells.

As noted earlier in this report, the goal of Task I was to test the devices in a field setting. Although I made a lot of progress in that direction, the prototypes fall short of what is needed to survive a field test. As noted above, a sensor is needed to detect the level of water above the PZ disks, turning electric power on or off in response to liquid level. That technology was not included with the TDK transducers. In May 2003, I found a person who could have provided the expertise to do those and other modifications. I intended to pursue that option during Summer 2003, but project funding was not extended soon enough to pursue that. By the time funding was extended in August, my time was very limited by the onset of duties for the Fall 2003 semester.

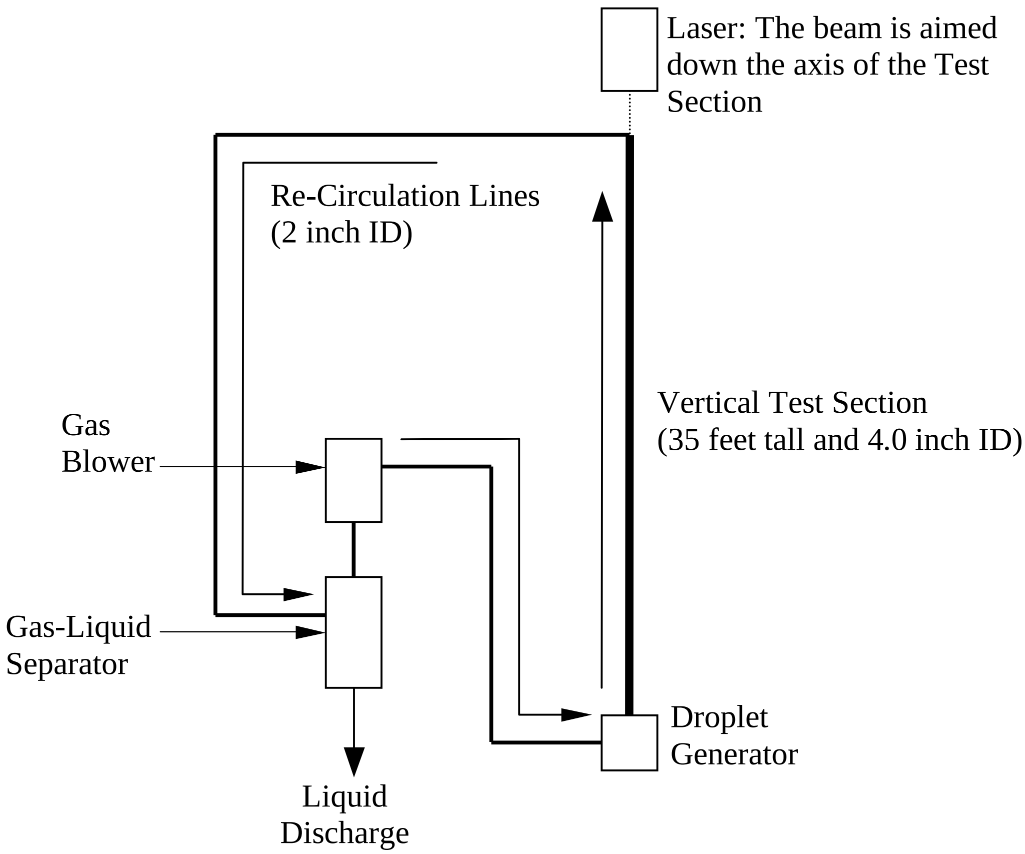

Figure 3. Schematic of Flow Loop.

Task II: Integrated modeling of gas well production. In this task, we continued efforts to model the combined system that consists of the reservoir and the well. We hoped that this effort would increase our ability to plan and interpret field tests of lifting technology, as well as our understanding of the benefits of effective liquid lifting. Although we did not complete an integrated model, we did investigate separately the reservoir and well-bore issues with modeling. We developed several models of gas reservoirs using Eclipse 100. Again, these single-well models were not integrated models – they are just reservoir models. However, we adjusted the operation of the well to reflect problems that occur in gas reservoirs. Specifically, we converted the well from a gas producer to a water injector at regular time interval to simulate cessation of gas production and the consequent imbibition of water that should have accumulated in the well-bore. The amount of injected water is small – less than 10 barrels. Such small amounts of water could accumulate in the production tubing during normal gas production; when production ceases, it would fall to the bottom of the well where it can be imbibed by the producing formation.

I also wrote well-bore models in Excel Visual Basic using the Gray model and the Duns and Ros model as described by Brill and Mukherjee(1999). These models were used mostly to investigate operating conditions in the flow loop.

Results and Discussion

Task I: Field testing of new technologies. This section begins with a brief discussion of the context of the problem of liquid lifting, continues with results of our research, and ends with discussion of feasible approaches for application of the results.

The root of the liquid-lifting problem in gas wells is droplet size. At high gas flow rates, liquids break into droplets of sufficiently small size for lifting by the gas. With decreasing gas flow rate, both the droplet creating capacity and the droplet lifting capacity decrease. This idea was succinctly represented by Turner, Hubbard, and Dukler (1969) in their expression for critical gas velocity v_c – the minimum velocity for dispersing and lifting liquid as droplets:

$$v_c = 0.567\left[\frac{(\rho_l - \rho_g)\sigma_{gl}}{\rho_g^{\;2}}\right]^{1/4} \qquad 1$$

Here, the critical velocity has units of ft/sec, the liquid density ρ_l and the gas density ρ_g have units of g/cm^3, the gas-liquid interfacial tension σ_{lg} has units of dyne/cm. If the velocity of gas declines below v_c, then liquid accumulation begins. For a natural gas-water system at 311 K and 689 kPa (100˚F and 100 psia), the critical velocity is about 6.7 m/sec (22 ft/sec).

In our previous research, we sought ways to stimulate production of droplets that can be lifted by velocities less than the critical velocity of Eq. 1. At critical velocities that are common to many of the gas wells in the Rocky Mountains, the droplets can be as large as 3 to 8 mm in diameter. Our previous studies showed that much smaller droplets could be produced by vibrational means. A correlation of droplet diameter and vibrational frequency is shown in Figure 4. According to Lang(1962), the size of droplets produced by vibration can be estimated with the following expression:

$$d = 0.34\left(\frac{8\pi\sigma_{gl}}{\rho_l f^2}\right)^{1/3} \qquad 2$$

In this expression, d is the droplet diameter(m or cm), σ_{gl} is the gas-liquid interfacial tension(mN/m or dyne/cm), ρ_l is the density of the liquid(kg/ cm^3 or g/cm^3), and f is the vibrational frequency (Hz or cycles per second). Tests performed in our previous project show that the Lang correlation can be extended to a very wide range of frequencies. One of the images from the droplet formation tests of our previous SWC project is shown in Figure 5.

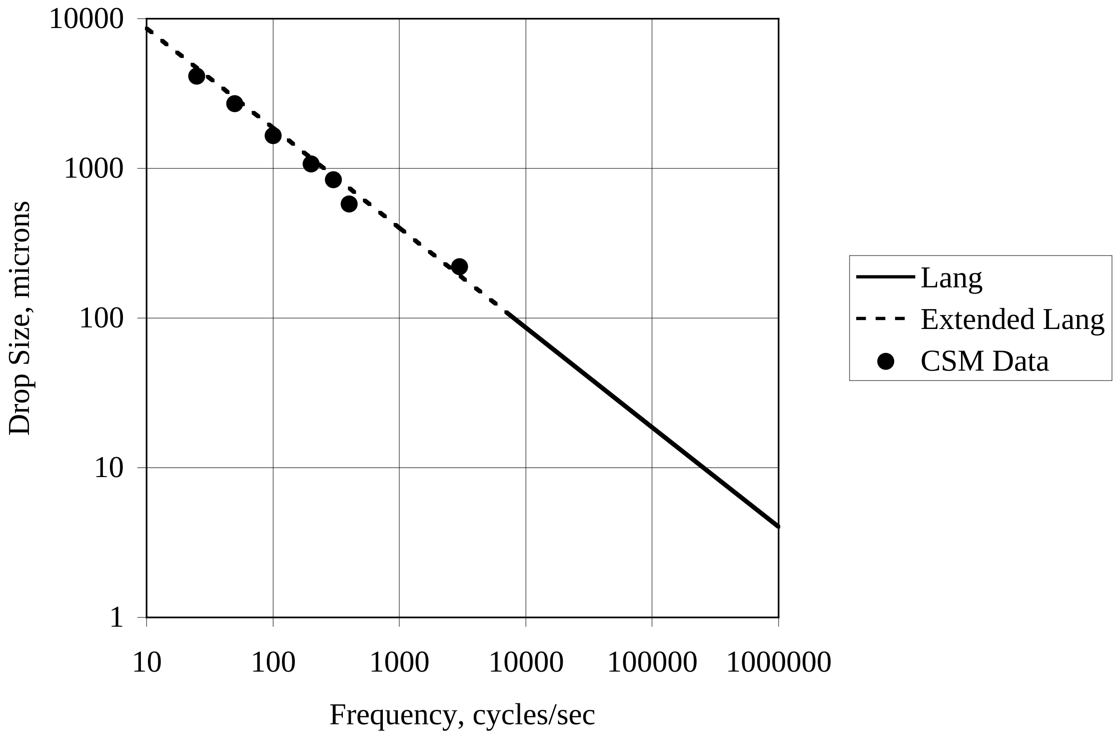

Figure 4. Extrapolating Lang's correlation to low frequencies quantitatively predicts our bench-top measurements.

Figure 5. Droplet formation at 200 hz.

As noted in previous sections of this report, the focus of Task I was to develop a device for field testing the vibrational approach for making very small droplets. Two prototypes were developed and tested in our flow loop. The objectives of these tests were to probe weaknesses in the designs of the prototypes and to assess the capacity for transporting the mist produced by the probes.

In tests with Model 1, gas flow rate was varied from about 5 MCF/day up to about 90 MCF/day. At rates up to about 60 MCF/day, the mist was carried up the 40 feet of the visible flow section and down the 40 feet of return tubing. At the highest flow rates, droplets impinged on the wall of the tubing. Furthermore, tests at the highest flow rates terminated prematurely because water partly filled the electronics chamber, disabling the transducer. At the highest flow rate, the prototype was subjected to pretty severe jostling as it was pelted with slugs of water.

The design of Model 2 responded to some of the weaknesses of Model 1. First, the aluminum heat sink was modified to take on the additional role as the bottom cap of the electronics chamber. This modification provides for more rapid transfer of heat to the flowing stream of gas and water around the prototype. Second, the power tube was added to provide a route for power connection through the top of the prototype and to provide a path for equalizing the pressure between the electronics chamber and the surround environment. Pressure equalization was needed because the PZ disk assembly is incapable of supporting more than a few tenths of a psi of pressure difference. Segregation chambers were added at the top of Model 2 to minimize opportunity for water entry into the electronics chamber through the power tube.

Tests with Model 2 have produced two interesting results. First, there was no entry of water into the electronics chamber through the power tube. Second, droplets were successfully transported even at the highest flow rate. The difference in droplet transport for tests with Models 1 and 2 is not understood. A bench-top test of Model 2 is shown in Figure 6. The mist can be seen flowing from the ports on the side of the model.

Figure 6. Bench-top test of Down-hole Device Model 2.

Both prototypes experienced a number of minor failures during testing that often consumed considerable time and patience to repair. As noted previously, there is no water-level sensor in the prototypes. Hence, one must be careful during operation to maintain sufficient water in the chamber above the PZ disk to prevent its self-destruction. The disk will self-destruct in a few seconds if there is not adequate water in the chamber. It is easy to lose track of this during testing process.

Neither of these prototypes is suitable for field testing. First, a level sensor is needed to prevent self-destruction of the transducers. Second, additional study is needed on the cable for providing power and support for the device. Third, a more robust mechanical design would be needed. The bottom cap is attached to the device with silicone sealant, which is sufficient for flow loop tests but not for field tests.

Task II: Integrated modeling of gas well production. For this task, I hoped to combine a model of reservoir behavior with a model of well-bore behavior. While this may be possible, I was not able to accomplish it within the time frame of this project. I was able, however, to complete some analysis of the two separate problems.

First, we wrote Eclipse 100 models to simulate the effects of water accumulation on gas production. One of the Eclipse 100 models is a radial model with horizontal permeability of 10 md, and vertical permeability of 1 md. The model is 60 feet thick. Cumulative production and production rate are shown in Figures 7 and 8 for a period of about 2200 days. Figure 7 shows that the cumulative production for periodic shut-in with re-injection of a small amount of water is about 20% less than that for continuous production of gas. Figure 8 shows the corresponding variations in gas production rate. After injecting water during the shut-in period, the gas production rate slowly rises toward the rate that is found for the continuous production model. Clearly, water that is not removed from the well has a significant detrimental effect on ultimate gas recovery.

The effect of changes in relative permeabilities and capillary pressure were on gas production were also explored with the radial Eclipse models. Relative permeabilities of the form of modified Brooks-Corey expressions were used in these models:

$$k_{rw} = k_{rw,\max}\left[\frac{S_w - S_{wr}}{1 - S_{gc} - S_{wr}}\right]^{nw}$$

$$k_{rg} = k_{rg,\max}\left[\frac{S_g - S_{gc}}{1 - S_{gc} - S_{wr}}\right]^{ng}$$

Specifically, we tested the effects of the exponents *nw* and *ng*. Increasing one of these exponents decreases the relative permeability of the associated phase. The results of these tests are shown in Figure 9 for intermittent injection of water as described in the previous paragraph. With *nw* and *ng* both equal to two, the effect of intermittent water injection on cumulative gas production is small. The effect on cumulative gas production increases as the exponents become larger. Values of *nw* are frequently between 3 and 5. (See Chapter 1 of Christiansen, 2001.) Generally, it is expected that exponents for the gas phase will be smaller than those of the water phase, because the water is considered the wetting phase. Relative permeabilities for very low permeability formations are rarely measured. Such measurements would be useful for evaluating the effect of water on cumulative gas production for the large gas reserves in the Rocky Mountains.

Changes in the threshold pressure of the capillary pressure relationship in the Eclipse model did not lead to significant changes in daily and cumulative gas production. This is surprising because I expect that the physical dimensions of the water saturated zone near the gas producing well to increase with increasing threshold pressure. This is a topic that deserves further study.

We also tested the effects of water on cumulative production from a “Cartesian” Eclipse model. In this model, a hydraulic fracture was simulated with a high permeability zone. Water was injected both intermittently and continuously into the portions of the fracture and the neighboring lower permeability reservoir. Results of these simulations were similar to those observed for the radial model.

These results suggest that a more careful evaluation of the effects of water on gas production is needed.

Second, I wrote Excel Visual Basic modules for well-bore simulation with the Gray model and the Duns and Ros model for two-phase vertical flow. (These and other two-phase flow models are described in Brill and Mukherjee.) I tested these models against performance in our flow loop. These models provided a lot of insight for interpretation of well-bore behavior, but there is much room for improvement. For example, many engineers in the industry maintain that a modified Hagedorn-Brown model is best for representing well-bore behavior. Other engineers favor mechanistic models. I used the Gray model primarily because it was very easy to write and it is widely used for simulation of wells with high ratios of gas to liquid production volumes. I chose the Duns-Ros model because of its foundation in laboratory data and because it provides a fairly comprehensive capability for well-bore modeling – it can represent bubble flow, slug flow, the transition from slug flow to annular mist flow, and annular mist flow regimes. These Excel Visual Basic modules are particularly useful for studies with the flow loop, but for actual well studies commercially available software is more useful. Such software incorporates heat-transfer effects, reservoir performance, complex well and surface designs along with the two-phase flow models.

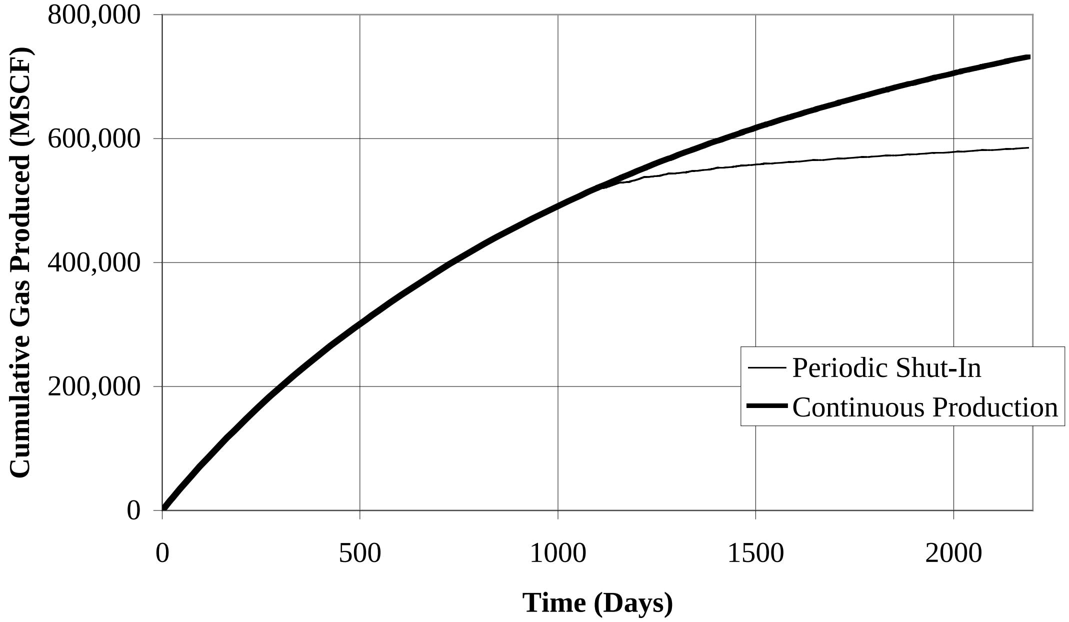

Figure 7. Cumulative production history for continuous production and for production with intermittent shut-in with water injection.

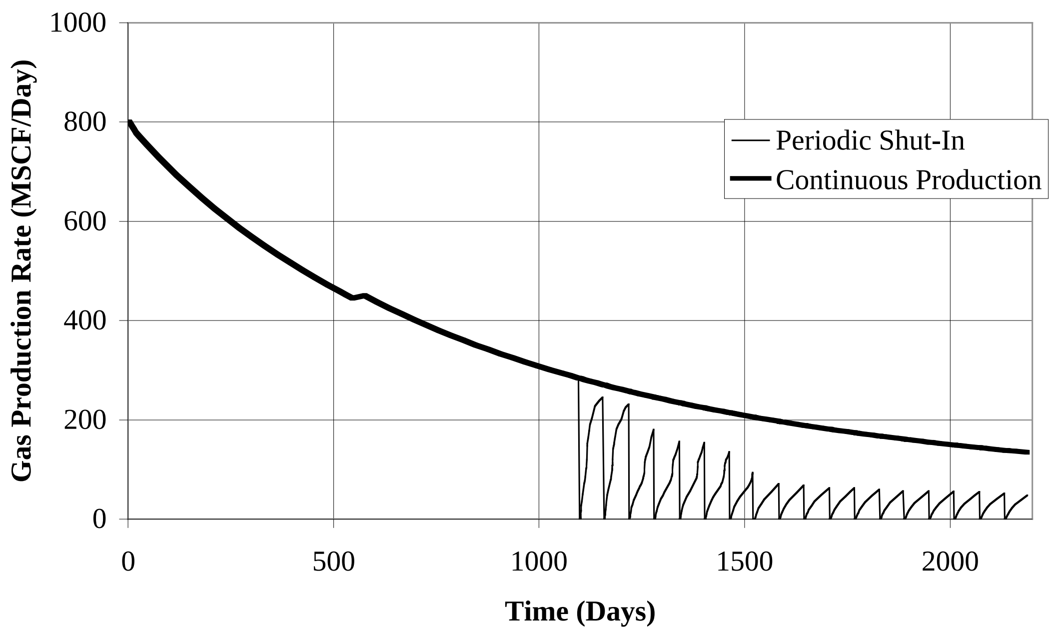

Figure 8. Production-rate history for continuous production and for production with intermittent shut-in with water injection.

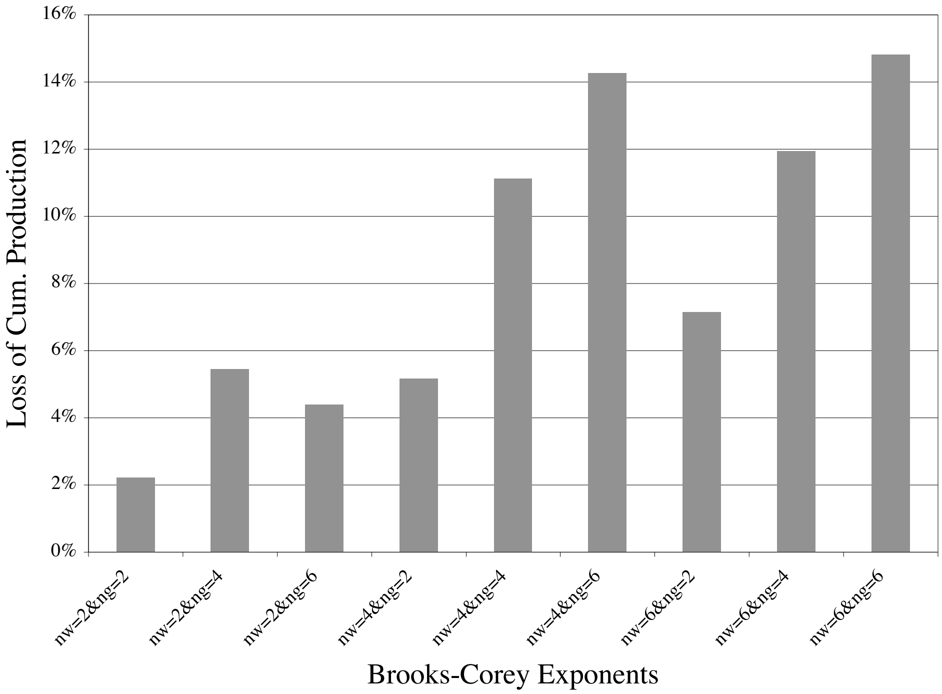

Figure 9. Loss of cumulative production after ten years with intermittent injection of water.

Conclusions

1. Droplets in gas wells at the critical gas velocity have maximum equivalent diameters of 3 to 8 mm according to analysis that is consistent with the model proposed by Turner *et al.*(1969).
2. Bench-top tests and analysis show that production of small droplets is possible with vibrational, rotational, and two-fluid devices. The Lang(1962) correlation quantitatively predicts the average size of droplets produced by vibrational means for frequencies from 20 Hz to 1 MHz.
3. Flow loop tests with 1.6 MHz ultrasonic transducers showed that 3-micron droplets can be transported a long vertical distance. Literature on separating liquid droplets from gas streams support this observation. We expect that droplets up to 30-microns can be transported to the surface. Flow loop tests with rotational devices failed completely. Flow loop tests with two-fluid devices were moderately successful.
4. The estimated energy costs of droplet production are low per stage: 3 to 30 cents/bbl for production of 30-micron droplets. If the droplets are less than 30 microns in diameter, just one stage may be sufficient. For larger droplets, multiple stages will be needed in a typical gas well.
5. Feasible approaches for application of vibrational droplet generators have been developed.
6. Simulation results show that production from gas reservoirs can be significantly diminished by incomplete removal of water from the wells.

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Final Technical Report- "A low cost oil water separator for stripper well applications"

Contract Start 5/22/02
Final Report Date 3/12/03

Final Report

Leland Traylor

Report Issued February 12, 2003

Subcontract Number 2282-PS-DOE-1025

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Abstract
Low cost oil-water-gas gravity type separators located in well, inside the production tubing, and used in conjunction with low volume submersible pumps were tested over the last nine months in four separate experiments in the field. The purpose of the tests was to show the usefulness of low cost separators in oil and gas wells, and to identify any problems that would limit their use in the field. The gravity separator technology tested was previously patented by Pumping Solutions Incorporated, and before this project, had not been field tested.

Four tests were performed, three at the RMOTC test facility in Teapot dome Wyoming and one at the Sanchez #1 well in the San Juan Basin in New Mexico. The separator as tested was low cost, and performed well in the field, except for a tendency to paraffin clog under some conditions. 99.7% oil-water separation was consistently achieved over a 6 month period with almost no operator intervention. As a bonus test, a gas well separator was designed and tested to demonstrate the use of the same concept to retrieve waste gas, contained in the pumped fluid, that is normally vented to atmosphere.

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Introduction

Over the past nine months, Pumping Solutions Incorporated, has been performing tests on a novel, low cost gravity separator that is used in conjunction with submersible pumps. These separators have the potential to replace more expensive, less environmentally friendly, surface separators commonly used today. The patented gravity separator technology uses the volume inside the production tubing as the separator volume, and is most useful at lower flow rates (less then 100 BPD) commonly found in stripper wells. Two types of separators were tested, oil-water and gas-water.

Executive Summary

Three low cost oil-water separators have been deployed to test wells at RMOTC, and a gas-water separator has been deployed in the San Juan Basin in a shale gas well. The oil-water separators were installed into Shannon formation wells with an average production of 20 BWPD and 3 BOPD. The average pump set depth was 800 feet. All wells were produced with submersible diaphragm pumps. The separators were installed into the standard 2 inch 8 round tubing from the surface after the submersible pump was installed. The total cost of the each separator was less than $50, not including the pump, cable, and standard tubing.

The first separator installed used 1 _ " PVC pipe as the separator "cup". Although the separator worked as designed, the separator "cup" was too large of a diameter, and eventually choked the flow and caused a downhole pump overload after about 1 week of operation.

The second separator installed was installed into the same well with a new pump. It had an improved separator "cup" which performed much better. The separation efficiency was measured by RMOTC to be 99.7%, which is better than standard surface gravity separators that had been used in that installation. The separator and pump ran continuously for 6 months, at which time, colder weather cause a paraffin clog near the surface that caused the pump to overload.

The third separator was installed on October 19th, 2002 in a nearby well of the same type. The separator performed the same as the previous installation for 2 months until extremely cold temperatures cause the surface tubing to freeze, causing the downhole pump to fail.

The fourth test was conducted in the San Juan basin, on a shale gas well. In wells of this type, most of the gas is produced in the annulus between the tubing and the casing, but a small amount of gas is produced up the tubing. This gas is normally vented to atmosphere when the pumped fluid is deposited into the water tank. A separator installed at the top of the tubing was able to separate the gas produced in the pumped fluid from the water, and was returned to the pipeline, thus creating more gas production and less greenhouse causing methane in the atmosphere.

The gravity separator as tested did perform well in a limited number of wells. Several problems were uncovered that will need to be addressed in future design iterations, but in general the separator performed better than expected, and PSI, under its own funding, will continue to test and deploy separators and will eventually offer these separators for sale with submersible pumps.

Experimental

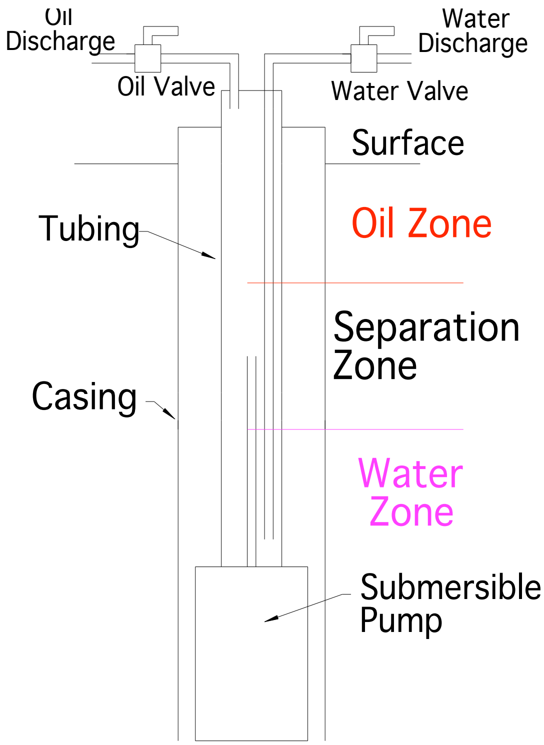
Four tests were performed during this Project. The first was installed on June 15 on a RMOTC Shannon well, which is producing stripper oil from the Shannon formation at about 1000' depth. The submersible pump was installed normally on 2" 8 round tubing by RMOTC personnel. The pump was started and run without a separator for a few hours. PSI personnel installed the PSI separator from the surface without a workover rig with the assistance of a RMOTC engineer. Once installed, the pump was turned on and the valves on the surface were adjusted to balance the flow of oil and water from the separator.

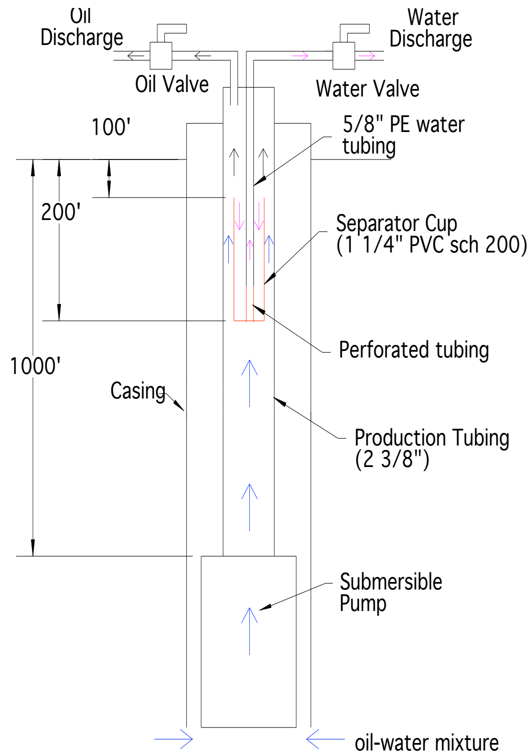
It was noticed that the exact adjustment of the valves is relatively sensitive, but once the proper flow rates are established, the flow of oil and water remains constant and completely separated. After the PSI personnel left to return to Albuquerque, the pumper continued to make minor adjustments to balance the flow. After about a week the pump failed, and was pulled and shipped to Albuquerque.

The pump was examined, and determined to have failed due to overload. Post test evaluation of the test hardware determined that the clearance between the separator "cup" and the wall of the 2 inch 8 round was too small, and an accumulation of sand had choked of the flow, and resulted in a buildup of excessive pressure, leading to pump failure.

A new pump was installed into the same well on Jun 21. The same day, the improved test separator was installed. The new design worked much better, and was less sensitive to small changes to the relative flow rate of the control valves. After a few days, a sample of the post separation fluids was tested by RMOTC and determined to consist of 99.7% oil, 0.3% water. The produced water had a "trace" of oil. The separator ran without incident for over 6 months, and after a few days of initial adjustment, has not required any additional adjustment to maintain relative flows. In mid December 2002, record cold temperatures were recorded in Wyoming. This froze over 45 wellheads in the area including the wellhead where this test was conducted. The freezing choked off flow, resulting in pump overload and failure, ending this particular test.

The third test unit was installed on October 19, 2002, into a Shannon well in the teapot dome field in Wyoming. It was essentially the twin of the unit installed in June and produced the same flow and separator characteristics, establishing the repeatability of the method. This unit ran approximately 2 months and was removed from service after an electrical failure of the submersible pump.





Test Hardware concept **Actual Test Hardware**

For all three wells described above, the tubing and casing was standard 4.5" casing, and 2 inch 8 round tubing that extended 1000' from the surface to the bottom of the well. It was installed in a conventional manner with the power cable banded to the outside. Once the pump was installed and operating, the separator was installed from the surface.

For units two and three, the separator was 100' long, consisting of a separator cup that was three sections of 20' 1 _" pvc schedule 200 pipe, joined by friction couplers. At the bottom end of the cup, the end was closed with a standard PVC cap. The cap was attached to an adaptor that connected the cap to the inner tube. The inner tube was attached to the cap through a 6 inch long, _"d pipe that had a number of holes drilled through it to allow the water to flow from the separator cup to the inner tube.

The pipe was attached to schedule 200, _" rigid pvc pipe, in 20' screw together sections. This extended from the pipe and the cap at the bottom of the separator cup to the surface. At the surface, the pvc pipe was connected to a bull plug that allowed flow through the wellhead through the bull plug.

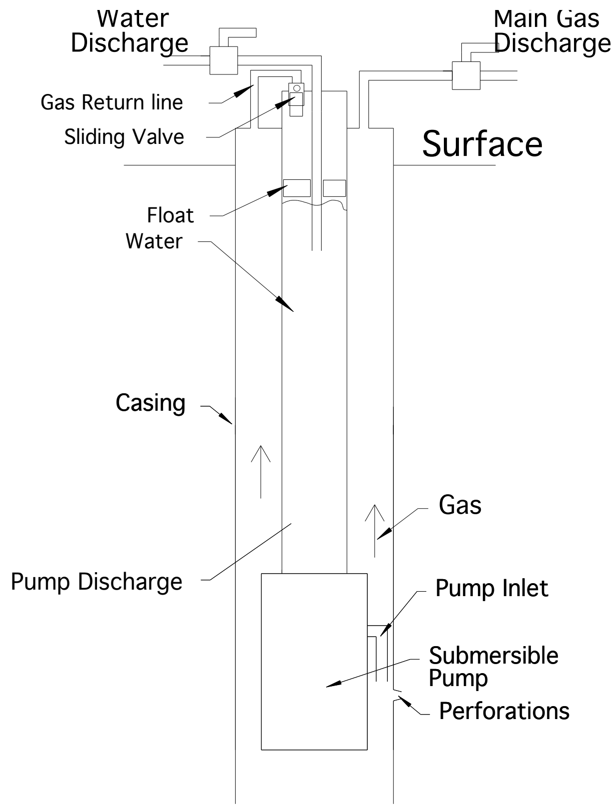
This inner pipe was connected to the water discharge control valve, which was a _" ball valve at the surface. The standard discharge control valve and discharge tubing at the surface, previously used to remove fluid from the top of the tubing string, was used to regulate the flow of oil at the surface

Separator ready for install

Post installation Wellhead

For the gas well unit number 4, the setup was much simpler, with a _" schedule 40 PVC water pickup tube extending inside the tubing from a fitting in a bull plug on the wellhead to inside of the tubing down 40 feet. At the surface, a "burp" valve was installed, where a floating ball would open or close a sliding type valve at the surface. When the ball was in the upper position, indicating little or no gas in the tubing, the sliding valve is closed, preventing the flow of gas from the tubing to the annulus. When the floating ball moved away from the sliding valve, the sliding valve would open, allowing gas to flow from the tubing to the annulus. The float was shaped like a "donut" allowing the water discharge tube to flow through the center.

The fourth test was conducted in the San Juan basin Sanchez well number two, installed on February 26, 2003, on a shale gas well. The well was 1900 feet deep and the pump was set below the perforations at 1800 feet. Unfortunately, this pump did not continue to run after the first day due to electrical problems. During the short time it did run, we were able to install the valves and float, but could not verify proper operation over a long time period. During the short time it did run, the separator seemed to be working, although some fluid leakage occurred around the gas purge valve. This problem will be corrected by adding o-rings, and after the completion of this project, this separator will be further tested with industry funding.



Gas Well Downhole
Separator

Results and Discussion

The gravity separator as tested did perform well in a limited number of wells and conditions. It appears that for situations of medium gravity oil, low flow rates, no emulsification, and limited paraffin formation, this low cost method will work very effectively. The major results of the testing were:

- For the types of oil and flow rates tested, 99.7% separation efficiencies were achieved
- A 200' long separator is all that is needed at apx 30 BFPD in 2 inch ID tubing
- Manual control valves work well, no need for automatic controls
- The separator can run long times with little attention if operated steady state
- Paraffin clogs can cause the separator to fail or require maintenance.
- Standard hardware costing less than $50 will create an effective gravity separator
- In well gravity separators can enable other techniques such as downhole water disposal and "tankless" direct injection into disposal wells

For the gas separator tested, the major results were:

- In well gas separators are practical, and although limited testing was conducted, such separators can be implemented with minimum hardware

- In well gas separators can reduce the amount of greenhouse causing gasses emitted from normally operating gas wells by recycling gas to the pipeline from the pumped fluid
- Only 20 feet of tubing is needed to create an effective separation zone
- A float operated valve works well, although more testing is needed

The test program performed is a good start to prove the concept is feasible, which was the goal of the project. Many more follow on tests are needed to show the extent to which the technique is useful. For the very limited conditions tested, the technique worked surprisingly well. Of interest is the single gas well separator tested, which allows an operator to produce a small quantity of gas from the pumped fluid, but more importantly, allows the operator to reduce methane emissions with little or no expense.

The operators used during this test program were lukewarm to the idea of using this type of separator, because it requires the use of a submersible pump and until the reliability and availability of low volume submersible pumps improves, it will be difficult to get operators to take the next step and install separators. PSI, under it's own funding, will continue to test and deploy this type of separator on a limited basis in conjunction with submersible pump testing. On the positive side, the technology will reduce costs, improve operations, and reduce pollution as advertised. The limited testing conducted shows the feasibility of the techniques, and the project has received notice of claims allowed for a US patent on the base separator technology (the patent was filed before this project started).

Follow on work that is suggested as a result of this field testing is:

- higher flow rates, and different types of oils and gasses.
- Direct reinjection of produced water into the same wellbore
- Tankless operations where the downhole pump pushes the separated water into a separate injection well under pressure
- In well oil storage for ultra low cost wells
- Use of larger liners with internally installed pumps

This work was sponsored by the Stripper Well Consortia, and that group has provided tremendous support for the development of low cost oil and gas well pumps and related techniques such as this project. The ultimate availability of low cost equipment such as described here can be attributed in large part to the efforts of the SWC.

Conclusion

When this project was proposed less than 1 year ago, the goal was to design, build, and test an entirely new type of downhole separator that would be a cost and performance breakthrough, reducing the cost of these operations an order of magnitude. The project has accomplished exactly what was proposed in about nine months. Although the magnitude of the project was relatively small, the design and field testing provided the proof required to perfect the design and make this a commercial product, able to reduce costs to producers. The task ahead is to make this now proven and tested technology commercial by refining the design, and completing the development and test of the low volume submersible pumps required to make it work.

Several surprising results were achieved. First, the proposers were not at all sure that the separator would work without complex (and expensive) controls. It turns out the system is very robust, and will work over a relatively wide range of manual valve positions. We are still investigating the physical basis of this welcome result. We believe that the differential density of oil vs water can explain this at least partially. The other pleasant surprise was the relatively short separator needed to achieve good separator efficiencies. We were expecting to need longer dwell times to achieve high efficiencies, but this was not the case. We may experience more difficulty trying to separate oils with different properties, but this will be part of later work. The third surprising result was the relative ease of integrating a gas separator into a gas production environment to recycle gas from the produced water to the annulus. This relatively painless technique does not really produce all that much more gas, but does eliminate some environmental and safety concerns using a relatively simple, cheap and reliable piece of equipment.

The goal of the next phase is to further demonstrate this technology and make it standard practice in the industry. The “big project” is to introduce low volume submersible pumps as a standard, but the availability of the technologies and techniques will make that easier, and will eventually make oil and gas operations lower cost and more environmentally acceptable.

Final Technical Report- “A method for using the production pump to continuously clean stripper wells”

Contract Start 5/22/02
Final Report Date 5/01/03

Final Report

Leland Traylor

Report Issued May 1, 2003

Subcontract Number 2287-PS-DOE-1025

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Disclaimer

Abstract
Cable Suspended Pump (CSP) works! This low cost system, which was used to deploy submersible pumps on continuous, flexible production strings completed first installation from a small trailer at RMOTC in December 2002. The flexible production string consists of three elements, the suspension cable composed of wire rope, electrical cable and plastic reinforced tubing. All three elements are deployed from the trailer from powered spools and joined about every 30 feet. The completed string has a wet weight of 500 pounds/1000 feet, and costs less than $2.00/foot. The most dramatic result was the improvement in installation speed and the reduction in cost due to the use of the relatively lightweight trailer. Installations were completed in less than 2 hours/1000 feet, with a one or two person crew using a rig that was towed behind a F-250 Ford truck.

The first installation went smoothly in a Shannon formation well in the teapot dome field in Wyoming. The purpose of this installation was to shake down the trailer, so the pump was installed to a depth of 600 feet, and the next day, removed from the well to determine if fixtures and procedures needed to be changed. As expected, further improvements in the hardware and installation techniques were made after this initial shakedown.

The second installation was made a few weeks later into the same well, and the pump was set at the bottom of the well, at approximately 650’. The pump was run for two months and then pulled. A significant design problem was discovered when we attempted to pull the pump. The clamping system used did not adequately prevent the tubing from “bunching up” at the top of the pump, and the design of the bottom adaptor caused the pump to pull to one side, tending to cause it to lodge against the casing and catch on downhole obstacles such as gyp rings.

Winter and a traffic accident stopped testing until April 27th-30th 2003, when two runs were made to 1000’ into the same well on consecutive days. This well is still in production on CSP and will be serviced by PSI when needed in the future.

Five additional test installations were completed as called for in the plan. These tests were or will be completed on conventional tubing as called for by the plan. These installations will be compared head to head with similar rod pumping installations under company funding.

Table of Contents

Introduction

Over the past year, Pumping Solutions Incorporated, has been performing tests on a novel, low cost production system that is used in conjunction with submersible pumps. This deployment system has the potential to replace more expensive 2 3/8" production tubing commonly used today. This patent pending system uses three strands deployed from powered reels at the surface. The first strand is the production cable, typically steel wire rope, the second strand is plastic insulated electrical cable, and the third is fabric reinforced polyethylene plastic tubing. The reels are mounted to a portable trailer that can be towed by a normal oil field truck and operated by one person. The purpose of the project was to deploy submersible pumps using this system to determine if it is useful and cost effective for stripper wells.

Executive Summary

This project produced significant results that far exceeded expectations. For the first time ever, a cable suspended pump was successfully deployed into a stripper well. Under the scope of the project, a completely new CSP trailer was designed, built and deployed. A new type of plastic high pressure, fabric reinforced hose was designed and built. Fittings needed to adapt the flexible string to the existing wellhead and to the submersible pump were developed. Finally, the submersible hydraulic diaphragm submersible pump itself received extensive test and run time as part of this project, including a head to head comparison that is just started and will continue well past the duration of this project under company funding.

The pumping system was deployed a total of four times after the trailer was completed in November 2002, and as a result, improvements were made that have resulted in a completely usable system for relatively shallow wells using submersible pumps. Another five installations using conventional installation techniques are planned or have been completed. The future installations will use equipment purchased using SWC funding, and will be deployed with company funds. The company plans to extend, under it's own funding, the technology to deeper wells, and other production situations such as Coal Bed Methane. Although not tested, system has been adapted to be used for conventional submersible centrifugal pumps, and for other types of wells, such as water wells.

The testing of the hydraulic diaphragm electrical submersible pumps (HDESP) was also significantly advanced by this project. Results from CSP

and conventional installations have proven some remarkable characteristics of this technology. HDESPs have the ability to pump up to 1.5% sand, will pump off with no damage, provide mixed flow (gas and liquid) pumping allowing higher production rates and have reduced power consumption up to 66%. This performance is from an all stainless steel and rubber pumps that weighs about 100 pounds and is 3 _ " in diameter, and costs less than half of a conventional pump. With an expected life of one to three years continuous operation, the technology is estimated to reduce artificial lift costs by 50% for a typical low volume installation. As a result of this proof of concept, a major pump company has partnered with PSI and will offer this pump and related products such as CSP as part of a major new branch of artificial lift technology.

Experimental

The experimental results are in two parts, the first section for CSP deployments and the second for conventional.

CSP Deployments

The trailer and string has been deployed four times at RMOTC, the first time was a dry run where the pump was placed and pulled on the same day to determine if the system works, and what changes are needed. The second run was "for real" into the same well after appropriate hardware changes were made in the field. The second time the pump was placed and remained in well for three months until it failed and was pulled with the trailer. The next two deployments followed the same basic plan after major renovations were made after the first pump was retrieved. The dry run was on April 24, 2003, when the pump was deployed and then retrieved to determine that the new hardware would not get stuck downhole. The second deployment was on April 29, 2003, and is still in operation as of the time of this report.

The first test was completed in mid November 2002, at the RMOTC in teapot dome Wyoming. A pump was placed by the trailer to a depth of 600' and then removed. All proceeded without incident, and a few design changes were identified for the first "for real" run. A few weeks later, in mid-December, with the design changes in place, the first run was made. The first run followed an unfortunate incident where our field man, Paul, was involved in a single car accident on an icy road in Southern Wyoming. The _ ton F-250 superduty truck pulling the CSP trailer rolled down an embankment after hitting an icy patch. Everyone was OK except the truck.

Truck and trailer prior to crash

The trailer was undamaged, and Paul proceeded to RMOTC to complete the installation. The second installation went smoothly, and the pump was placed in a Shannon well at 650' depth. Again, several design changes were identified as a result of this run. The plan was to leave the trailer at the location and remove the pump in a few months time to determine if the system was working properly. In early February, a record breaking cold snap occurred in the Wyoming area, and froze a large percentage of the wellheads in the RMOTC field, including the test wellhead. When the pump was started, fluid could not flow, and the tubing burst at the pump end of the string. The pump was undamaged.

CSP Wellhead

We returned to RMOTC in late February to retrieve the pump from the well using the trailer. Several difficulties were encountered trying to pull the pump, which we later learned were the result of small but correctable problems with the design of the adaptors used for the test. When the pump was pulled, the pump became stuck downhole, 10's of feet above the original location. After much effort, the suspension cable was snapped in two in an attempt to retireve the pump by the suspension cable. An attempt was made to retrieve the pump by pulling the tubing. Fortunately, this succeeded in retrieving the pump and the electrical cable.

After the pump was removed and the remains examined, two problems came to light. First, the wire rope cable connection to the adaptor had come off center because of poor design assumptions. This off center pull cause the top of the adaptor to dig into and slide along one side of the casing, rather than in the center. The corner of the adaptor soon encountered gypsum deposits which caught on the end of the adaptor. This was enough resistance to arrest the upward movement of the assembly regardless of how hard we pulled. After the cable broke, the suspension was switched to the fluid tubing, which was on center, and released the stuck pump from the grips of the casing.

The second problem encountered was that the tubing and electrical cable were not attached firmly enough to the suspension cable, causing it to slip and become piled up at the top of the pump when we were moving the pump up and down to free it from the casing.

Two corrective actions were identified. First, the adaptors were redesigned to achieve an on center pull, and all flat surfaces facing upward have been removed. The shape of the adaptor was changed from a "can" shape to a "football" shape to facilitate the adaptor's movement up the casing. The second corrective action is to improve the connection between the tubing, electrical cable, and suspension cable by providing a layer of tape between the elements before the clamp is applied. The tape fills in the gaps and achieves a tighter fit at the clamp.

Also, as a result of this experience, the trailer was damaged, as the drives for the tubing were never designed to take the load applied to remove the pump from the well. The operator also suggested that we change from constant speed drives to constant force drives to simplify the operation of the trailer, and that a guard be added to make the trailer easier to set up.

Several interesting results came about after the tubing used in the test was examined at the surface. First, no degradation was suffered by the tubing in any way. The plastic and reinforcement layers were 100% intact. The inside surface of the tubing was completely clean, with no evidence of any mineral or paraffin buildup. The approximate velocity of the fluid in the tubing, when the pump was running, was 2 ft/sec. We also observed that the inside of the tubing was very smooth, and this may have also contributed to the lack of build up. Although the diameter of the tubing was relatively small, the tubing showed no signs of constriction. Although paraffins were found in the metal sections (adaptors, surface piping etc), significantly, no build-up was observed in the tubing itself.

CSP being installed

Tests number three and four were completed after extensive modification of both the trailer and the fittings. Test number three, which was a temporary installation to determine that the new fittings were not going to become stuck downhole, was conducted on April 24th 2003 at RMOTC into a Shannon formation well at 900 feet. The pump was successfully deployed and retrieved on the same day with no incident.

The following week, the fourth deployment was completed on April 29,2003 into the same Shannon formation well. The installation was made and completed in less than 4 hours, including final hook-up and pump up. The improvements over the previous installations were an improved adaptor with an on center pull and no sharp corners and improvements to the clamps, including the use of tape to improve the fit, and tape to cover the clamp "tags" to make sure they do not catch on the well coming up. This pump is currently in operation, and when required will be pulled with company funding.

Conventional Installations

Over thirty HDESP installations have been made in the past 24 months to various stripper and gas wells to determine the performance of and improve the design of the submersible diaphragm pump. To date, the average run time has been about 4 months, with the run time improving constantly with design changes. The HDESP is currently awaiting the arrival of a vastly improved diaphragm that has been in the works for the past 6 months. This change is the final step in the design evolution of the HDESP. Even without the new diaphragm, the pump has been proven as a result of the test program.

The PI had hoped to be able to conduct some of the final CSP and conventional installations with the new diaphragm, but this will not be possible within the time constraints of the SWC. We have recently deployed to the field three pumps as part of the conventional installation program that was approved as part of this project. Two pumps have been shipped and will be deployed to Bretagne G.P. in Kentucky as part of a side by side comparison between rod and HDESPs over the next year. Two more pumps will be sent to Betagne once the first two are installed, and the hope is that the new pumps will have the vastly improved diaphragms. Another pumps has been shipped to QuickSilver resources for use in stripper service in Michigan. The three pumps that have shipped are equipped with conventional diaphragms. The later two, plus any replacements required, will have the new diaphragm. Additionally, once reliable pumps with new diaphragms are available, more pumps will be sent to Geopetro, Quick Silver, Nobel (in Oklahoma) and Chatachwa energy, as well as other sites selected from SWC membership. All of the hardware shipped plus the two additional pumps use hardware that is part of this SWC program. The company will pay any additional expenses for hardware or deployment that occurs after this project is terminated.

Results and Discussion

Because of the successful development and deployment of this system, many more tests are planned, leading to full commercial deployment of both the HDESP and the CSP deployment system. A new DOE funded CSP test field is being put in place in the Red Mountain field in Western New Mexico this summer to show deployment on a wider scale. Approximately 30 deployments are ultimately planned for that project using exclusively CSP technology. A major pump company is also planning to test the system this summer in submersible centrifugal produced coal bed methane wells in Wyoming with the hope of deploying CSP centrifugal pumps this summer.

CSP Trailer at RMOTC

The goals as stated in the original proposal were as follows:

- Determine what tubing types will work with submersible pumps under real well conditions
- Design and build a prototype pull and run system to install pumps and tubing in wells
- Test the system under realistic test well and field conditions

In addition, SWC increased funding to provide for five additional deployments of the HDESP pump. This and a head to head comparison of this lifting technology vs conventional rod pumps will be accomplished as part of this project. It can be safely said that the project accomplished in one short year the stated goals and more.

A very usable, commercial cable deployed pumping system has been developed and tested under this program; the first CSP system ever used for low volume stripper wells. In addition the PSI Hydraulic Diaphragm

Electrical Submersible Pump is well on the way to being a commercially available product. We are partnering with a large, international artificial lift supplier that has committed to put significant resources into the final development engineering and ramp up to production required to make this product generally available.

Conclusion

The SWC can take pride in it's support of this technology development in the earlier stages that was needed to bring it to the point of general application. The model we have followed of innovation, development, testing and finally partnering with an existing, large company appears to be very efficient in moving technology from the lab to market. The benefits outlined in the original application are now closer to reality as a result of this process. PSI will continue to innovate and support pumps and related equipment, concentrating on deployment systems (like CSP) and innovative application solutions such as on site power generation equipment and specially pump applications.

HDESP pumps will become a significant new technology for lifting fluids from stripper oil and gas wells, as a result of this project and other development activities. With the new partnership between PSI and a major artificial lift company, we predict that these pumps will become generally available within the next year. CSP is a significant enhancement to the usability of this pump technology and has been and will continue to be developed as a result of this project. PSI is encouraged with the results so far, and expects that CSP will be generally available soon after the HDESP pump comes on the market.

Review and Selection of Velocity Tubing Strings for Efficient Liquid Lifting in Stripper Gas Wells

Final Technical Report
May 15, 2002 to April 30, 2004

Submitted By:
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Disclaimer

Abstract

This project generated a set of liquid lifting curves specifically for use with low-rate (<60 Mscfd) gas production wells. The curves were tested against a 300 well data set compiled from Great Lakes Energy Partners, LLC's Cooperstown gas field. From this data set, one study well was chosen to test a novel tubing installation. Although production difficulties occurred following velocity string installation, which did not allow a pre- to post-insertion performance comparison, several key insights for the determination of critical rate were made.

It was determined that liquid droplet shape can have a large impact on the terminal rate calculation. Since the drag coefficient is highly dependent upon the particle, calibration of the correct critical rate values to field observations is a necessary step when under taken a similar study. So, liquid lifting performance charts were generated using formulations by Turner (spherical droplet) and Li (flat-droplet). Further , the use of surface conditions to determine terminal velocities and then critical rates is an acceptable practice for tubing-completed wells, providing the tubing is set to the perforations.

In addition to the liquid lifting charts, the project conducted a coarse tubing availability survey to ascertain if small diameter (< 3 inch) tubing was readily available for "off the shelf" use.

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Executive Summary

For low-productivity (stripper) gas wells, the accumulation of liquid in the wellbore can be detrimental to the well's productive life. Quite often, the operator may turn to means other than the natural reservoir energy to lift the accumulated fluids. These may include mechanical pumping, adding wellhead compression, plunger lift, gas lift, soaping, siphon strings or a variety of other methods that can require significant capital investment as well as increased operating costs and equipment maintenance. However, the installation of smaller diameter tubing strings (velocity tubing), if properly identified, can minimize cost while improving well productivity.

When using small diameter completion strings (< 3 inches), large pressure drops that can be associated with two-phase (gas-liquid) flow in the tubing and the potential lack of tensile strength may be important factors to consider. Nonetheless, for stripper gas wells, the impact of frictional losses may be minimal due to the well's small production rate while the implementation of coiled tubing may provide the strength necessary for deeper and smaller applications.

This project surveyed tubing and coiled tubing suppliers in order to obtain performance measures such as outer diameter, wall thickness, relative roughness and tensile strength for compilation into a stand-alone reference. In addition, regional availability of tubing and coiled tubing providers as well as inventory was determined.

Further, a literature review identified those two-phase correlations that are most applicable for stripper gas wells and small diameter production tubing. This review served as the basis for the construction of liquid lifting performance curves for use in sizing tubing strings for low rate gas wells.

The project team tested the liquid lifting performance curves on a candidate pool of wells provided by Great Lakes Energy Partners, LLC. It was determined that Turner's formulation for terminal velocity, and therefore critical rate, understated the ability of the Cooperstown Medina gas wells to lift liquids under their own energy. However, a formulation developed by Li, et al, demonstrated that while Turner's concept was correct, the assumption of spherical droplets was erroneous when applied to wells within the study reservoir, resulting in the use of Li's formulation for development of the improved liquid lifting charts.

From this study set, a test well was chosen. This well had its existing completion string (1-1/2 inch nominal, 2.75 #/ft) pulled in order to install a smaller diameter PL Resin *Thermoflex* velocity tubing string (1 inch nominal), allowing the well to produce under its natural energy. Although the well experienced production difficulties soon after installing the velocity tubing string, resulting in no tangible, comparative results, several key conclusions and insights were made during this research project.

- It was determined that liquid droplet shape can have a large impact on the terminal rate calculation. Since the drag coefficient is highly dependent upon the particle, calibration of the correct critical rate values to field observations is a necessary step when under taken a similar study. So, liquid lifting performance charts were generated using formulations by Turner (spherical droplet) and Li (flat-droplet).

- The use of surface conditions to determine terminal velocities and then critical rates is an acceptable practice for tubing-completed wells, providing the tubing is set to the perforations.

- Tubing providers have on hand, for the most part, tubing sizes in the range of 1 to 3 inches. However, little/no roughness information exists for aid in the determination of friction pressure drop.

- When computation of downhole pressure drop is necessary, formulations by Hagedorn and Brown were found to be the most precise.

- Frictional pressure drop can be greatly reduced through the use of lower-cost, higher-strength plastic (smooth) pipes. These low-friction tubulars are best applied in shallower applications.

- Turbulence damping was also found to reduce friction, suggesting a high-strength seam on the inside of tubulars may be beneficial.

Introduction

When produced gas no longer provides the energy necessary to lift liquids out of a well, the result is the bottomhole accumulation of liquids (liquid loading). This event can be characterized by a production rate that is no longer able to keep the liquid phase moving in the wellbore. It has been reported that to effectively remove liquids from the well, the required gas velocity must be at least 5 to 10 ft/sec for hydrocarbon liquids and 10 to 20 ft/sec for produced water[1,2,3]. If this minimum velocity is not met, liquid loading will occur, creating an additional backpressure on the formation from which the well typically cannot recover without operator intervention.

Once liquid loading occurs, the operator may have several options for unloading wellbore liquids and restoring production. These often include adding compression, mechanical pumping, plunger lift, smaller tubing, siphon strings, gas lift, soap injection and flow controllers. However, many of these techniques, require higher capital and operating costs as well as an increased maintenance frequency[4]. Further, the use of small diameter tubing strings for the removal of liquid can effectively curtail production due to larger pressure drops in the production string. Therefore, the operator must carefully consider the total cost and impact of the application with regard to the expected production benefit.

For low productivity wells; however, the influence of the frictional pressure drop may be negligible when considering the impact of down-sizing the production string and its increased ability to remove wellbore liquids and increase productivity. In fact, Hutlas, et al reported that although the installation of small diameter tubing may have limited utility due to large associated pressure drops at high flow rates, it can be an ideal, cost-effective application for wells near the end of their productive life[5]. Nevertheless, several authors have reported on the installation of velocity tubing strings in wells producing in excess of 300 Mcfd with a degree of success[2,6], suggesting low productivity stripper wells may benefit.

With the introduction of coiled tubing for use as permanent completion equipment, the production engineer was presented with an additional set of options. Smaller diameter coiled tubing can now provide the necessary strength for placement either in deeper wells[7] or to be used as a conventional, yet slimmer completion. In 1999, it was estimated that nearly 15,000 wells have implemented the use of coiled tubing as a velocity or siphon string[8]. Today a wide variety of coiled tubing options are available for implementation in a range of sizes as small as 0.25 inches, creating a multitude of choices for the production engineer.

In order to make the correct choices regarding well and reservoir development, the production engineer must often manage with the concept of minimizing expenditure while maximizing the return on investment. To aid the operator in this endeavor, ARI proposed to generate easy to use, liquid lifting performance curves for small diameter tubing.

Background

The initial work on the subject of critical rate to maintain liquid removal from oil and gas wells dates back to 1961. Duggan studied gas condensate wells and determined that a linear velocity of 5 ft/sec (at the wellhead) was sufficient for continuous liquid removal[1]. Later studies were able to expand upon Duggan's work to account for water-gas systems, which ultimately suggested that 5 to 10 ft/sec was necessary for hydrocarbon liquids while 10 to 20 ft/sec was required to lift produced water[2,3].

However, the classic work on the subject was conducted in 1969 by Turner, Hubbard and Dukler[9]. Two physical models for the transportation of fluids up vertical conduits (tubing) were created: 1) the liquid film model and 2) the liquid droplet model. The liquid film model concerned itself with the removal of accumulated liquids on the walls of the pipe while the droplet model centered about the removal of liquids in the gas stream. During the study the authors were able to show that the liquid droplet model was the dominant liquid transport mechanism and that it should be considered for further understanding the liquid lifting process.

Turner, et al was able to show that when drag forces equate to acceleration forces for a free-falling liquid particle, the particle will reach terminal velocity, which is the maximum velocity it will attain under the influence of gravity. This velocity is a function of the shape, size and density of the liquid particle as well as the density and viscosity of the lifting medium (gas). Therefore, to suspend a liquid droplet, the gas velocity should equal the terminal velocity of the drop and any incremental gain in gas velocity should result in upward movement of the droplet. The resulting relationship showed that the larger the droplet, the larger the terminal gas velocity, and the larger the gas rate necessary to remove the droplet from the well.

The study assumed that all droplets were spherical and had a maximum Weber number of 30. Further, the investigators assumed the drag coefficient for a sphere (**Figure 1**) lied between Reynolds numbers of 1,000 and 200,000, which on average is a value of 0.44. This resulted in the familiar form of Turner's equation:

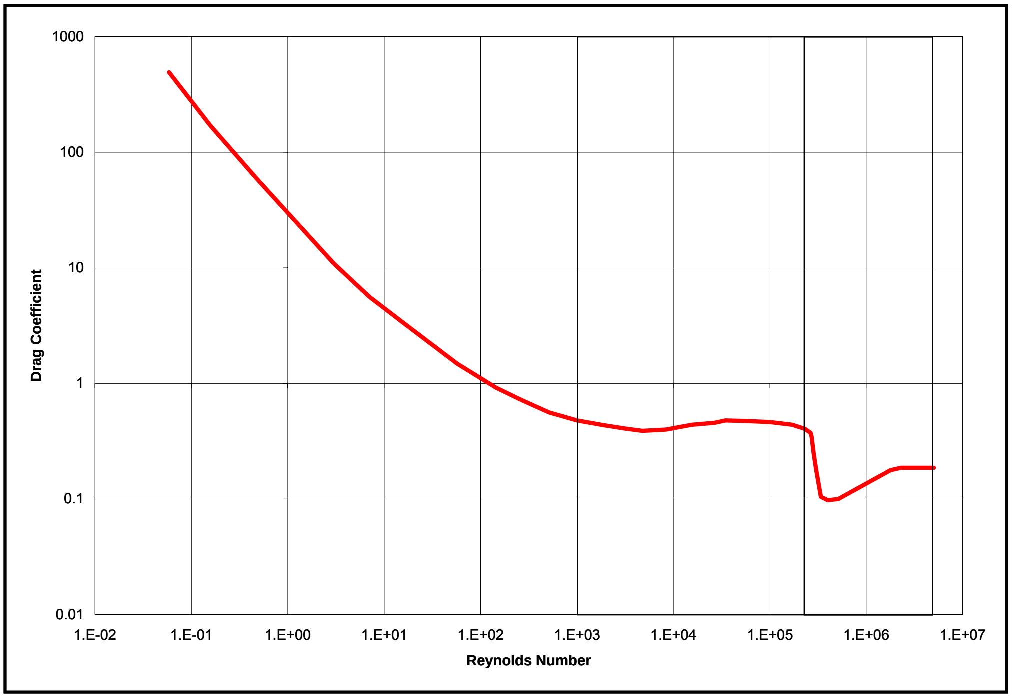
$$\boldsymbol{v_t = \{17.6\ \sigma^{0.25}(\rho_L - \rho_g)^{0.25}\} / \rho_g^{0.5}}$$

When the investigators compared their formulation to the data set, they realized that a nearly 20% upward adjustment of the equation was necessary to match the data. The following is Turner's adjusted equation:

$$\boldsymbol{v_t = \{20.4\ \sigma^{0.25}(\rho_L - \rho_g)^{0.25}\} / \rho_g^{0.5}}$$

In 1991, Steve Coleman, et al published a series of journal articles discussing the various aspects of understanding and predicting gas well load-up[10]. The authors, working the same gas field as Turner, showed that the 20% upward adjustment was unnecessary to match the observed field behavior, at that time. Further, they were able to demonstrate that wellhead conditions (pressure, temperature) controlled the ability to lift fluid from

Figure 1 – Drag Coefficient vs. Reynolds Number for Spherical Elements



the well, that liquid-gas ratios below 22.5 bbl/MMscf had no influence in determining the onset of liquid loading, and that the amount of condensed water increases in the production stream with declining reservoir pressure.

Additional work on the topic was provided by Nosseir, et al, who recognized the deficiencies of Turner's work and developed critical velocity correlations for varying flow regimes, such as the transitional and highly turbulent, which supported Turner's turbulent flow equations[11]. The investigators also deduced that the differences between Turner's and Coleman's work was due to Reynolds number and its impact upon drag coefficient.

Initially, Turner had assumed that valid Reynolds numbers for the field were from 1,000 to 200,000, where in fact the Reynolds numbers actually exceeded 200,000, when calculated by Nosseir. This should have resulted in a smaller drag coefficient (**Figure 1**) and therefore a larger critical velocity, supporting Turner's 20% increase. Nosseir's work also shows that those same wells, during Coleman's study, actually exhibited Reynolds numbers from 1,000 to 200,000, supporting Coleman's use of Turner's equation without the 20% increase.

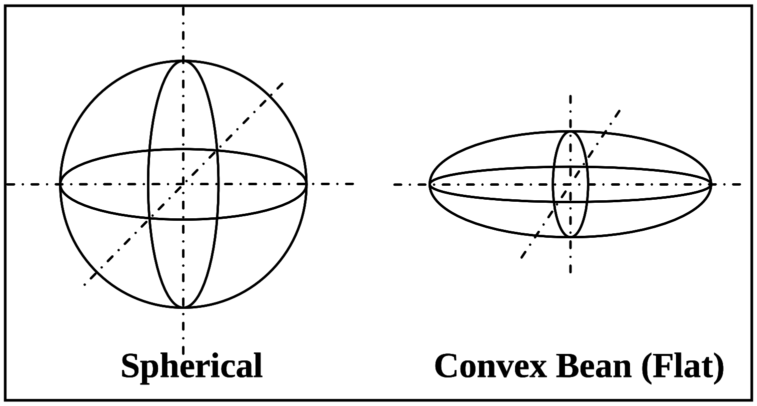
Finally, in 1991, Li et al showed that by varying the shape of the droplet from spherical to disk-shaped (flat), they were able to better match field behavior [12]. **Figure 2** depicts a comparison of spherical and convex-bean (flat) shaped droplets. Through this droplet shape model change, the investigators were able to show that the increase in drag coefficient (1.0) reduced the necessary critical velocity. Their formulation was as follows:

$$v_t = \{8.2\ \sigma^{0.25}(\rho_L - \rho_g)^{0.25}\} / \rho_g^{0.5}$$

For all formulations, terminal velocity can be used to determine the critical rate using the following formulation:

$$q_c = 3.06\ p\ v_t\ A\ /\ T\ z$$

Figure 2 – Comparison of Spherical and Bean (Flat) – Shaped Droplets



Methodology

The production behavior of stripper gas wells can best be characterized by many years of relatively stable gas production with moderate decline rates. When the gas rate falls to the point at which liquids cannot be removed from the well, the column of fluid creates an additional backpressure on the well that after a time can lead to severely reduced gas production rates.

In the event that liquid production is not being removed, this work presents a beneficial system of charts for determining if the installation of smaller tubing will benefit a particular well. When sized appropriately, velocity strings can provide the operator with many years of stable production using the natural energy of the reservoir to produce wellbore liquids. These liquid lifting performance charts present a variety of tubing sizes less than three inches. Benchmarking was conducted against a pool of potential candidates, from which one test well was selected for the installation of a permanent small diameter velocity flow string.

This project also surveyed tubing and coiled tubing suppliers in order to obtain performance measures such as the outer diameter, wall thickness, thread type (tubing), relative roughness and tensile strength for compilation into a stand-alone reference. In addition, regional availability of tubing and coiled tubing providers and inventory was determined to estimate the type/size of tubing readily available.

Additionally, literature was reviewed to identify those two-phase correlations that were most applicable to stripper gas wells and small diameter production tubing. This review served as the basis for the construction of liquid lifting performance curves for use in sizing tubing strings for low rate gas wells.

Work Plan

In order to complete this work, ARI formulated a thorough and cost-effective strategy for the creation of well performance charts for use with low-productivity wells. This work was divided into six main tasks, which are discussed in detail below.

Task 1 (Survey and Technical Review) – The project team conducted a provider survey concerning tubing and coiled tubing availability and performance standards. Properties such as outer diameter, wall thickness, thread type (for tubing), relative roughness and tensile strength were requested, while maintaining regional diversity.

Following the provider survey, a detailed literature review was conducted to identify the most technically relevant pressure drop and liquid lifting methodologies for use in the creation of the low-productivity liquid lifting performance charts. Each correlation was reviewed with regard to its applicability with stripper gas production wells and small diameter (> three inches) production tubing.

Task 2 (Liquid Lifting Performance Charts) – Combining the results of the technical review and the tubing/coiled tubing supplier review, liquid lifting performance charts were constructed for a wide variety of wellhead pressure values. Liquid density was also considered in order to account for hydrocarbon liquids and high-density brine.

Task 3 (Test Well Classification and Selection) – The project team worked closely with the operator, Great Lakes Energy Partners, to select candidate test wells that would benefit from the installation of small diameter tubing. Initially, a significantly larger pool of candidates was reviewed on a well-by-well basis to ascertain the applicability of velocity tubing strings. This necessitated the creation of and electronic completion dataset and the organization of a production database for over 300 Cooperstown gas wells.

Next, the liquid lifting charts were reviewed to ascertain whether or not the well is currently producing at a gas rate sufficient to lift liquids. If so, the well was not considered a candidate and would be removed from the test well pool. If the charts indicated small diameter tubing may be beneficial, the well was categorized as a candidate. From this final group of wells, up to three wells with the most promising upside would be selected as the final test wells.

Task 4 (Tubing Replacement) – Once the candidate wells were selected, the operator made the appropriate preparations for installing the small diameter tubing string. Generally this process involved the removal of the existing tubing string and the insertion of the smaller diameter tubing string.

<u>Task 5 (Monitor Production)</u> – Following the insertion of smaller diameter tubing in the gas wells, the project monitored production performance for the duration of the program. Well production volumes were collected for comparison to pre-workover production rates.

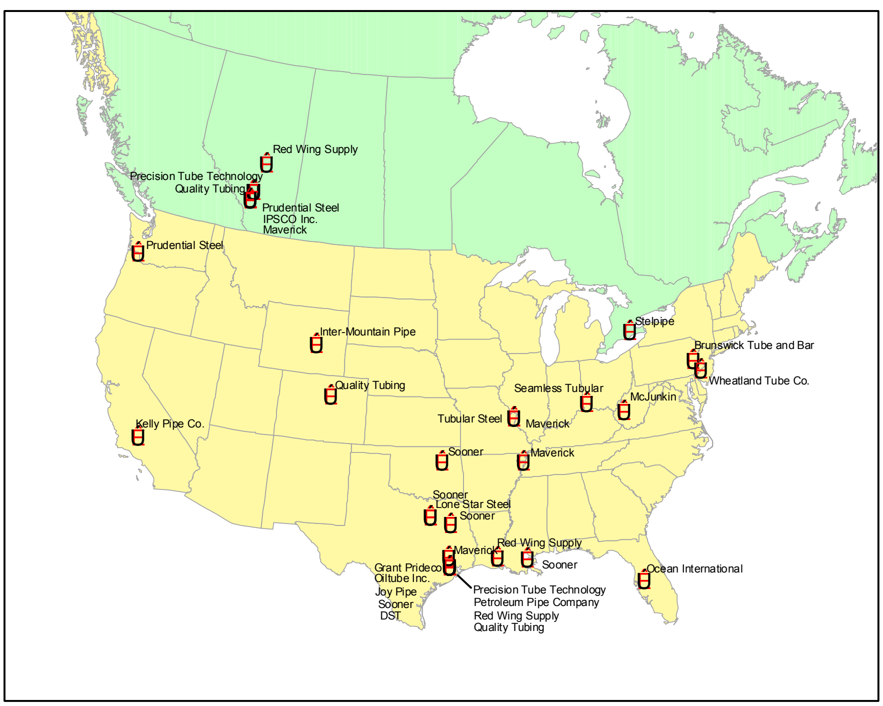
Results and Discussion

Supplier Survey

The project team conducted a provider survey concerning tubing and coiled tubing availability and performance standards. Properties such as outer diameter, wall thickness, thread type (for tubing), relative roughness and tensile strength were requested, while maintaining regional diversity. **Figure 3** depicts the geographic diversity of those who responded to the survey while **Table 1** shows the results of the survey, highlighting the available sizes and grades.

For the responding coiled tubing suppliers and those tubular suppliers that sold made to order (MTO) tubing, all diameters could be fabricated but required lead-time. All suppliers cited American Petroleum Institute (API) standards for their tubing, note the designated grades on **Figure 3**. However, none of the suppliers were able to provide roughness information. **Appendix A** contains contact information for all suppliers contacted.

Figure 3 – Tubing Supplier Survey Respondents



Literature Review

Following the provider survey, a detailed literature review was conducted to identify the most technically relevant pressure drop and liquid lifting formulations for use in the creation of the low-productivity liquid lifting performance charts. Each correlation was reviewed with regard to its applicability with stripper gas production wells and small diameter (> three inches) production tubing. See **Appendix B** for an annotated bibliography.

For pressure drop correlations, Brill and Mukherjee were able to show that a modified Hagedorn and Brown formulation was superior to all other formulations, including those of Duns and Ros, Orkiszewski, and Beggs and Brill[13]. Since the Hagedorn and Brown formulation was developed on data gathered in a 1,500 foot deep well, with tubing diameters of 1, 1-1/4 and 1-1/2 inches[14], it appears to be the formulation for use when the determination of bottomhole pressure data is necessary from surface data. However, when considering the velocity necessary to lift liquids from the wellbore, several authors have shown that wellhead conditions are the limiting factor, when tubing is properly installed to the perforations[2,9,10].

Further, the literature was able to show that pressure drops can be reduced through the use of internally coated or smooth pipes[15,16]. However, scale and/or tool running can degrade this benefit. In addition, Azouz, et al, were able to demonstrate that seamed coiled tubing actually exhibited lower frictional pressure drops than seamless coiled tubing due to turbulence damping[17]. However, interviews with coiled tubing providers indicated that this seam presents an erosion and corrosion base for the gas/liquid/oil[18].

Liquid Lifting Performance Charts

Based on the results of the literature survey conducted during Task 1, ARI had decided to begin the construction of the liquid lifting charts using formulations developed by Turner,

Table 1 – Small Diameter Tubing (< 3 inches) Survey Results by Respondent

			Common Sizes							Variable Sizes				Grade				
Vendor	**Location**	**Coiled**	**1"**	**1 1/4"**	**1 1/2"**	**2 1/16"**	**2 3/8"**	**2 7/8"**	**3"**	**<1"**	**1"-2"**	**2"-3"**	**MTO**	**J**	**K**	**L**	**N**	**P**
McJunkin	Charleston WV				■		■	■						■				
Ocean International	Lakeland FL												■					
Lonestar Steel	Dallas TX					■	■	■			■			■	■			
Stelpipe	Welland ON		■	■	■	■	■	■	■					■				
Precision Tube	Houston TX, Red Deer AB	■																
Prudential Steel	Longview WA, Calgary AB						■	■						■				
Quality Tubing	Houston TX, Denver CO, Red Deer AB	■																
Oiltube Inc.	Houston TX, Aberdeen UK						■	■						■		■		■
Grant Prideco	Houston TX																	
Red Wing Supply	Lafayette LA, Houston TX, Edmonton, AB					■	■	■						■	■	■	■	■
Sooner	Texas Locs, New Orleans LA, Tulsa OK					■	■	■						■		■	■	
Brunswick Tube & Bar	Allentown PA																	
Petroluem Pipe Co	Houston TX												■					
Joy Pipe USA	Houston TX						■	■						■		■	■	
Tubular Steel Inc	St. Louis MO		■	■	■	■	■	■	■	■	■	■		■		■	■	
Maverick	St. Louis MO, Conroe TX, Calgary AB, Hickman AR					■	■	■						■		■	■	
Wheatland Tube	Collingswood NJ		■		■				■	■	■	■						
Inter-Mountain Pipe Co	Casper WY					■	■	■			■			■				
Steel Group Inc.	Chicago IL						■	■						■				
DST	Houston TX						■	■			■			■				
Kelly Pipe Co	Bakersfield CA						■	■						■				
IPSCO Inc.	Calgary AB						■	■			■			■				
Seamless Tubular	Newport KY						■	■						■		■	■	■
Koppel Steel	Ambridge PA						■	■						■		■	■	■
Consolidated Pipe & Supply	Birmingham AL						■	■						■				
Benoit	Houma LA						■	■			■	■		■		■	■	■

MTO = Maid-to-order

Hubbard, and Dukler[9], without the 20% upward adjustment. Since this formulation was valid for Reynolds Number values between 1,000 and 200,000, it should be very similar to those conditions for low-productivity gas wells. Further, the literature review showed that it would be acceptable to utilize surface conditions (pressure) for the determination of the critical lifting rate. The test site for these liquid lifting performance charts was the Dempseytown quadrangle of Great Lakes Energy Partner's (Great Lakes) Cooperstown gas field, which spans Crawford and Venango counties, Pennsylvania.

For the dataset, Great Lakes supplied paper copies of the completion information for 394 gas production wells and electronic version of all gas and limited water production data. Within this subset of wells, there existed newer wells that still produced under their own energy as well as older wells that produced with rabbits and surfactants. The field is, for the most part, equipped with 1-1/2 inch nominal tubing to the top, or very near, of the perforations. Relevant data for the Cooperstown gas field is shown in **Table 2**.

Table 2 – Study Reservoir Properties

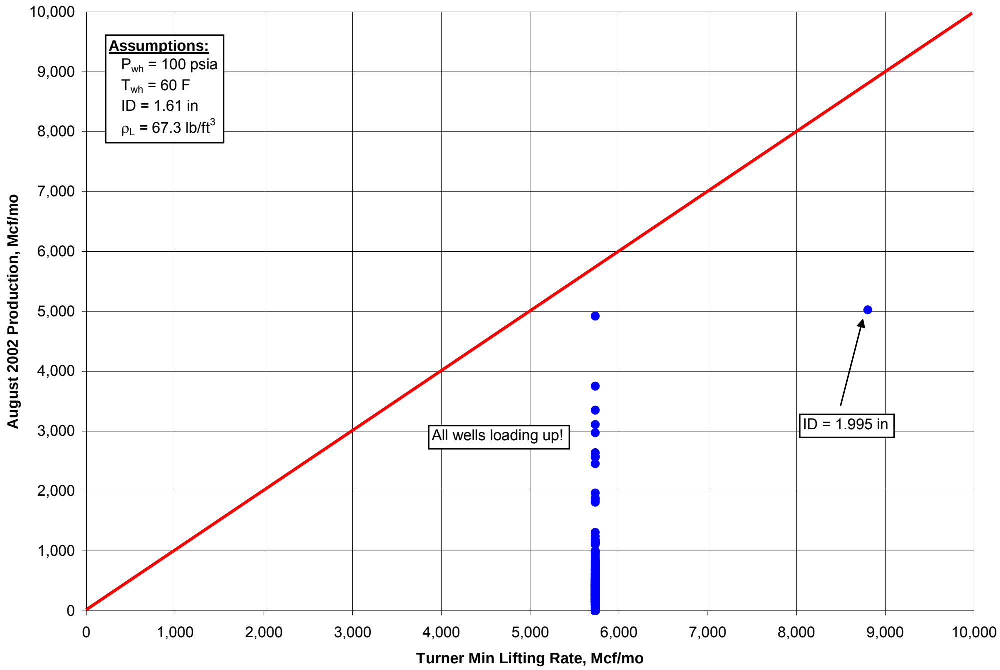
Location: Cooperstown Gas Field, Dempseytown Quadrangle			
Reservoir		Production	
Formation:	Medina	Relevant Date:	Aug-02
Number of Wells:	394	Cumulative Gas:	64.4 Bcf
Average Depth:	5,323 feet	Cumulative Water*:	68 Mbbl
Average Perf Thickness:	61 feet	Average Cum Gas:	163 MMcf
Average Gas Gravity:	0.6	Best Avg. GasYear:	47 MMcf
Average Water Density:	9 ppg		

*132 wells reporting from 1986 to 1997

Figure 4 depicts the August 2002 production rates for the 394 well dataset plotted against Turner's predicted minimum lifting rate. This plot takes the observed field gas production rates, in Mcf per month, and plots them against the expected critical velocity in the same units. The red diagonal depicts the division between observed field rates sufficient to lift fluids (above the red diagonal) and observed field rates insufficient to lift fluids (below the red diagonal). Following the construction of this figure, a conversation with Great Lakes reinforced the fact that a number of these Medina gas wells (+/- 5) were new wells and still producing under their own energy, lifting liquids and should have been plotting above the diagonal line.

Thus, a comparison of Turner's work with Cooperstown gas field production data has shown that the Turner formulation does not correlate with the observed field production behavior. That is, Turner's correlation has understated these well's ability to produce gas and liquids naturally. Conceptually, wells plotting below the red diagonal line should be experiencing liquid load-up behavior and wells plotting above the red diagonal should produce fluids naturally. As shown in **Figure 4**, all wells should be "theoretically" loading-up.

Figure 4 – Critical Rate Determination using Turner's Method



This effect was also witnessed in methane production wells in China by Li, et al[12], where the operators often were required to compute the Turner minimum lifting rate and adjust it downward by as much as 2/3. The authors then presented formulations similar to those of Turner, implementing a bean-shaped (flat) droplet in lieu of the spherical droplets used by Turner. This new formulation, when applied to the production data set, was able to identify approximately ten wells that were able to produce liquids under their own energy (**Figure 5**).

Again, observed gas production rates are plotted against the computed critical lifting rates. However, in this instance, a handful of gas wells plot above the diagonal line, demonstrating their ability to produce reservoir fluids under their own energy and agreeing with field data observations. A comparison of Turner's adjusted and unadjusted formulations for critical rate determination to that of Li's is presented in **Figure 6**, with Great Lakes wellhead operating pressures highlighted within the yellow band.

Using Li's formulation for low pressure wells, liquid lifting curves were generated for a variety of nominal tubing diameters between ¾ and 2 inches using the following water density and gas gravity values:

Figure 7 – Water density of 9 ppg and gas gravity of 0.60.
Figure 8 – Water density of 9 ppg and gas gravity of 0.65.
Figure 9 – Water density of 10 ppg and gas gravity of 0.6.

A Microsoft Excel worksheets has been included to calculate critical rate using Li's formulation (Tubing Charts – Flat Droplet.XLS). A comparison of the variation between these parameters (**Figure 10** for one inch nominal tubing) is presented for review. From **Figure 10**, it is clear that while liquid and gas properties can affect the lifting rate, the bigger impact is a change in the tubing size (as shown on **Figures 7-9**).

Candidate Well Selection
Once the liquid lifting performance charts were constructed, the next step in the process was to select appropriate candidate wells for tubing replacement. The ideal candidate wells were those that would benefit most, from a production standpoint, by down-sizing the production tubing string. In general, the qualities of these wells are:

1. Relative gain in productivity
2. Higher than normal reservoir pressure
3. Competent wellbore condition

This procedure was further complicated by the fact the Medina formation in the Cooperstown gas field is sufficiently deep (>5,000 feet). Thus, the use of conventional “off-the-shelf” one inch nominal steel tubing and plastic (smooth) tubing was implausible since each would pull themselves apart under their own weight.

Figure 5 – Critical Rate Determination using the Li, et al Formulation

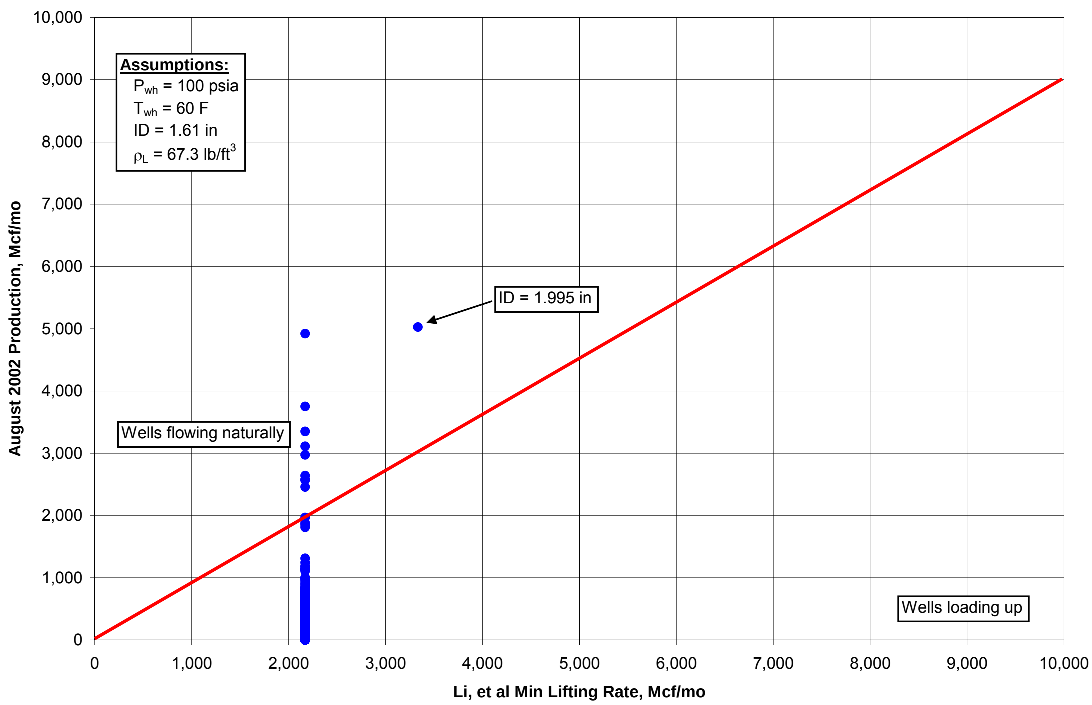


Figure 6 – Comparison of Critical Rate Formulations

Figure 7

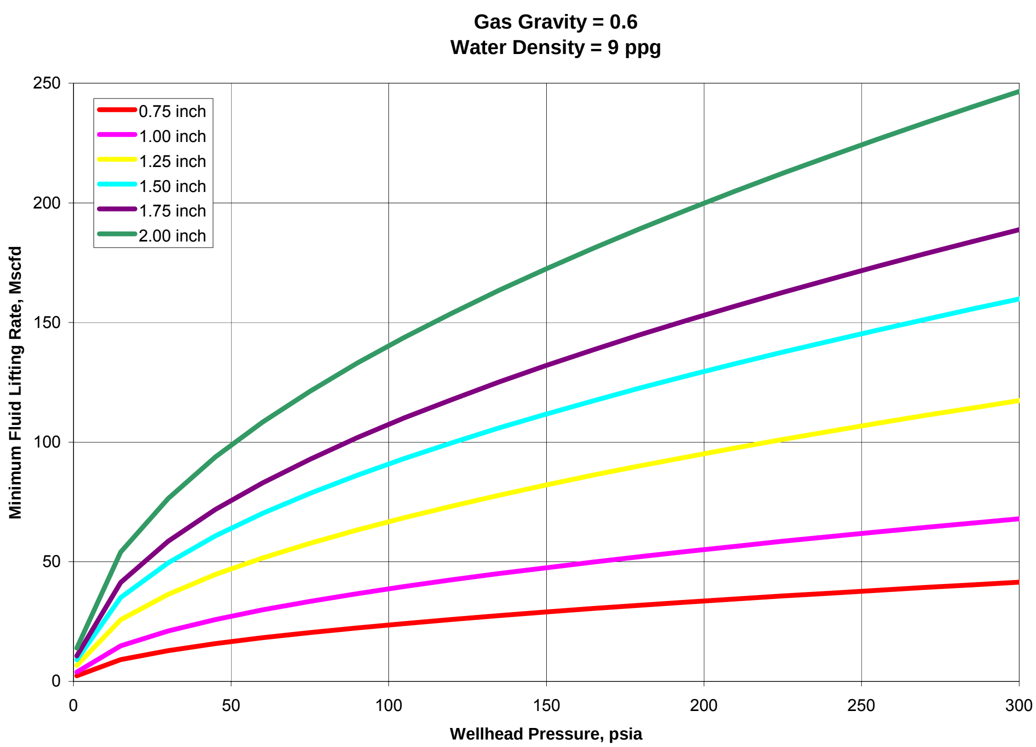


Figure 8

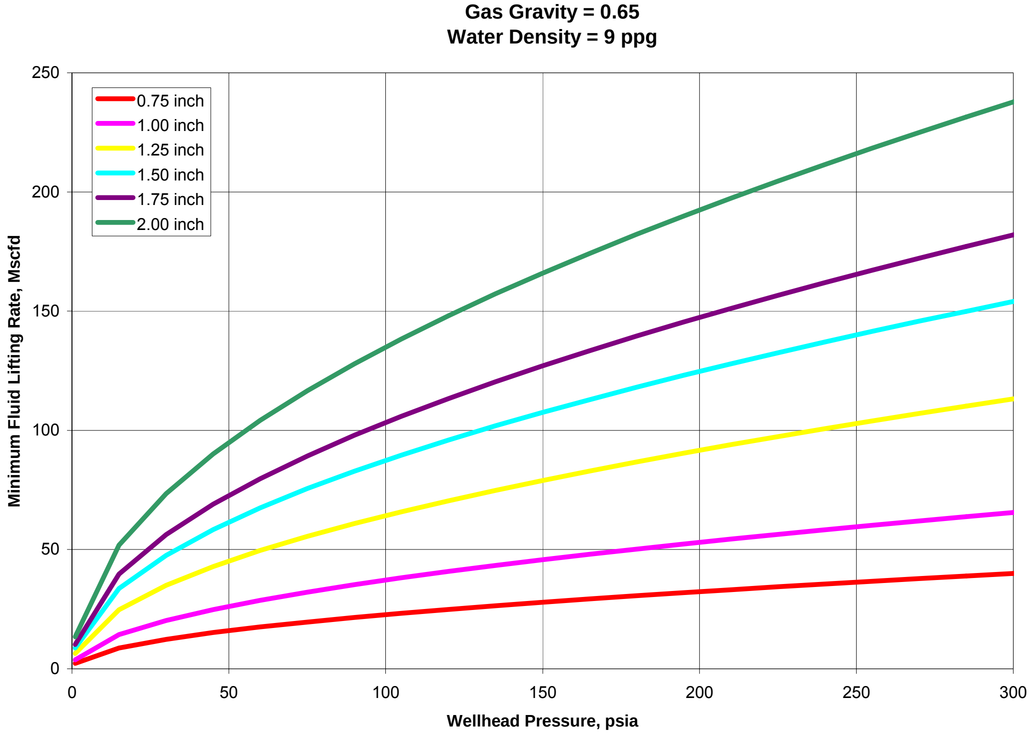


Figure 9

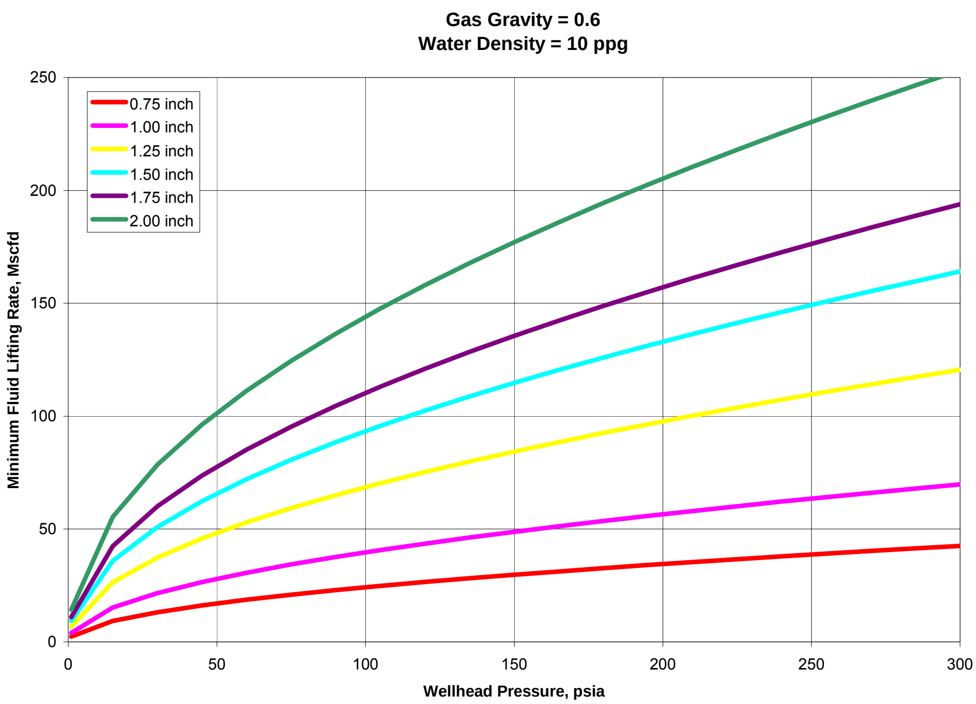
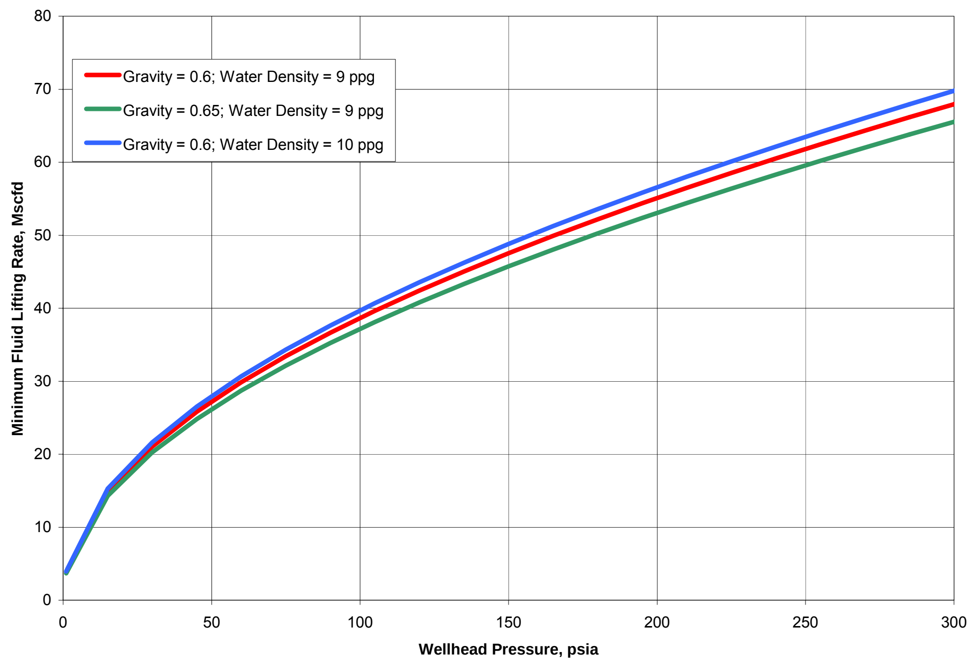


Figure 10 – Impact of Gas Gravity and Liquid Density Variations on Critical Rate (1" Nominal)



So, when Honeywell offered to allow the testing of their new PL Resin *Thermoflex* continuous velocity tubing string in a Great Lakes well, it seemed like a natural fit. Unfortunately, due to cost consideration of implementing this particular type of continuous velocity string and its unproven nature meant that only one candidate well would be tested under this project. **Figure 11** depicts and provides a description of the tubing.

Great Lakes, Advanced Resources International and Honeywell came to an agreement that of the potential test wells in the study area, the Two Mile Run #8 (TMR8) was the ideal candidate. As a newer well, the TMR8 would exhibit higher than average reservoir pressure, which would contribute directly to long-term productivity gain, and a relatively high-quality completion. Typical completion and production parameters for the TMR8 are shown in **Table 3** and a production plot of the well's natural flow history is shown in **Figure 12.**

Table 3 – Study Well Properties

Location: Two Mile Run Park #8			
Reservoir		Production	
Total Depth:	5,868 feet	First Date of Prod.:	6-Sep-02
Top Perforation:	5,645 feet	Production to:	3-Feb-03
Bottom Perforation:	5,697 feet	Cumulative Gas:	11 MMcf
Average Perf Thickness:	52 feet	Peak Gas Rate:	94 Mcf/D
Tubing String:	5,660', 1-1/2", 2.75 #/ft	Cumulative Water:	165 Bbl
Installed Spring Plunger:	3-Feb-03	Average Water Prod:	1.3 Bpd

Figure 11 – Thermoflex Velocity Tubing String Properties (after Honeywell)

A comparison of Turner's and Li's critical rate formulations to the TMR8's pressure and production history again shows (**Figure 13**) that the Li formulation is superior for this field. While the Turner estimates for critical rate are more than twice the actual production rate for the natural flow history of the well, the flat droplet theory formulation tracks production in a more reasonable manner. Note that the well produced under its own power until early February of 2003, when a spring and plunger were installed in the well. **Figure 14** depicts the production profile of the well prior to installing the velocity tubing string.

Tubing Replacement

Installation of Honeywell's PL Resin *Thermoflex* reinforced flexible tubing was undertaken on December 9, 2003. The installation consisted of pulling the existing 1-1/2 inch tubing and swabbing approximately 80 feet of fluid, which corroborated on earlier Echometer survey indicating a liquid column in the well. This was followed up by rigging up Lenape Resources' spool truck containing the 1 inch flexible tubing (**Figure 15**).

A mule shoe was connected to the tubing end and the velocity string was run in the hole to a depth of approximately 1,812 feet, where a steel tubing splice was installed before

Figure 12 – TMR8 Production History

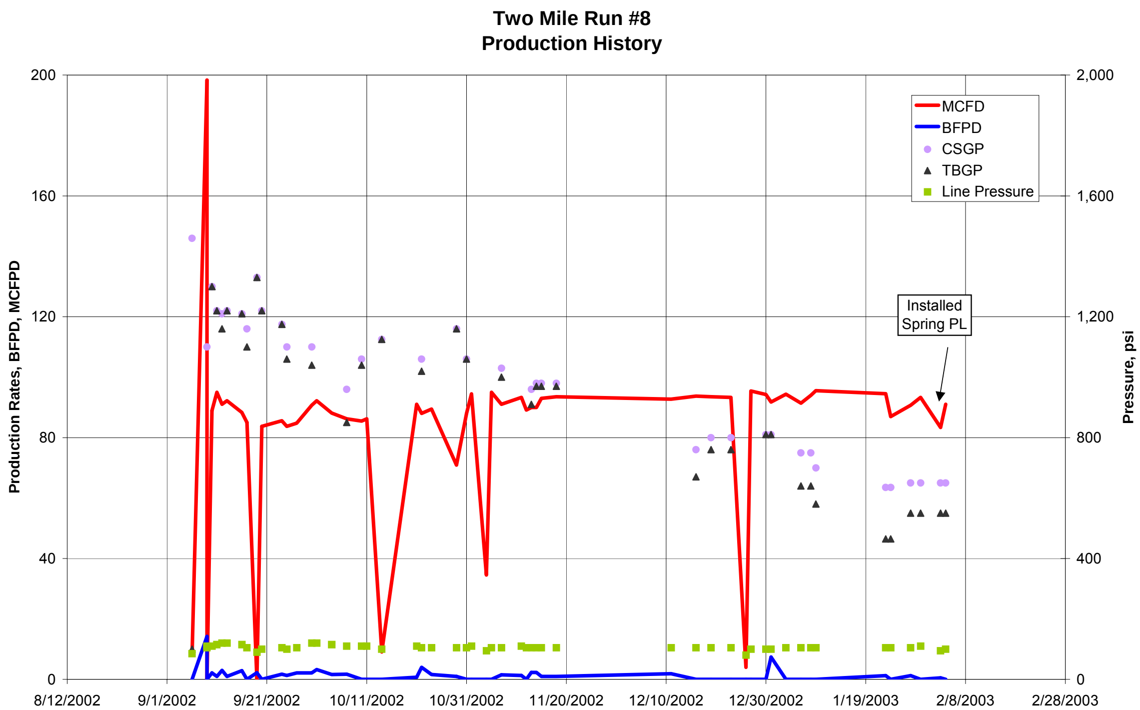


Figure 13 – Turner, Li Critical Rate Formulation Compared to TMR8 Production Rate

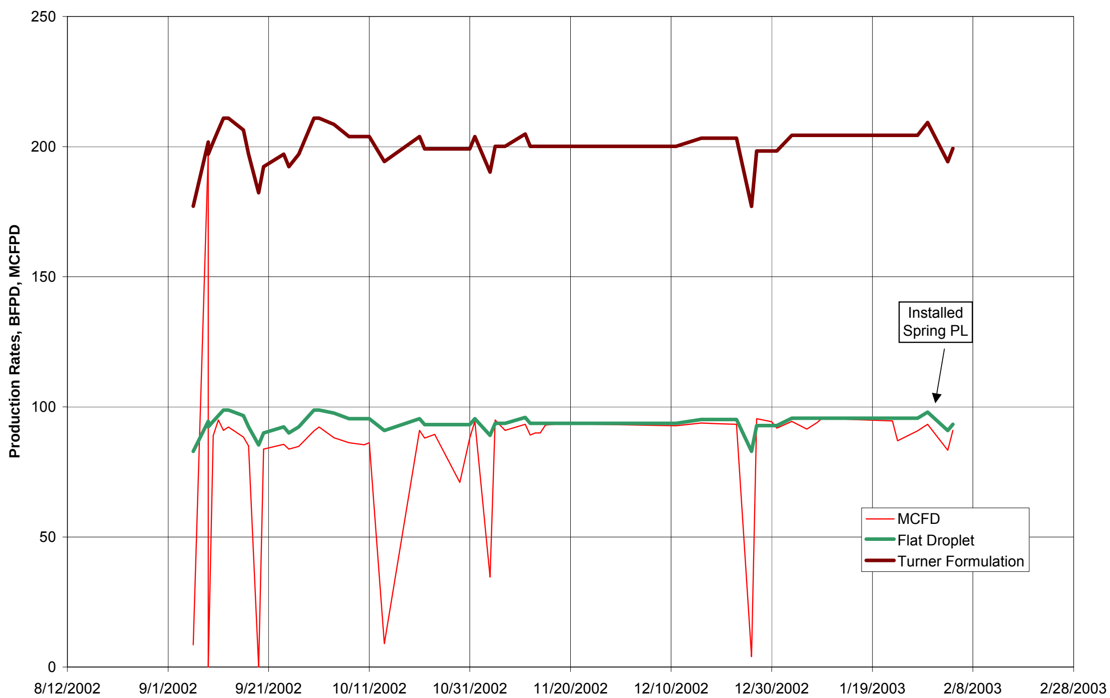


Figure 14 – TMR8 Production Performance Prior to Velocity String Installation

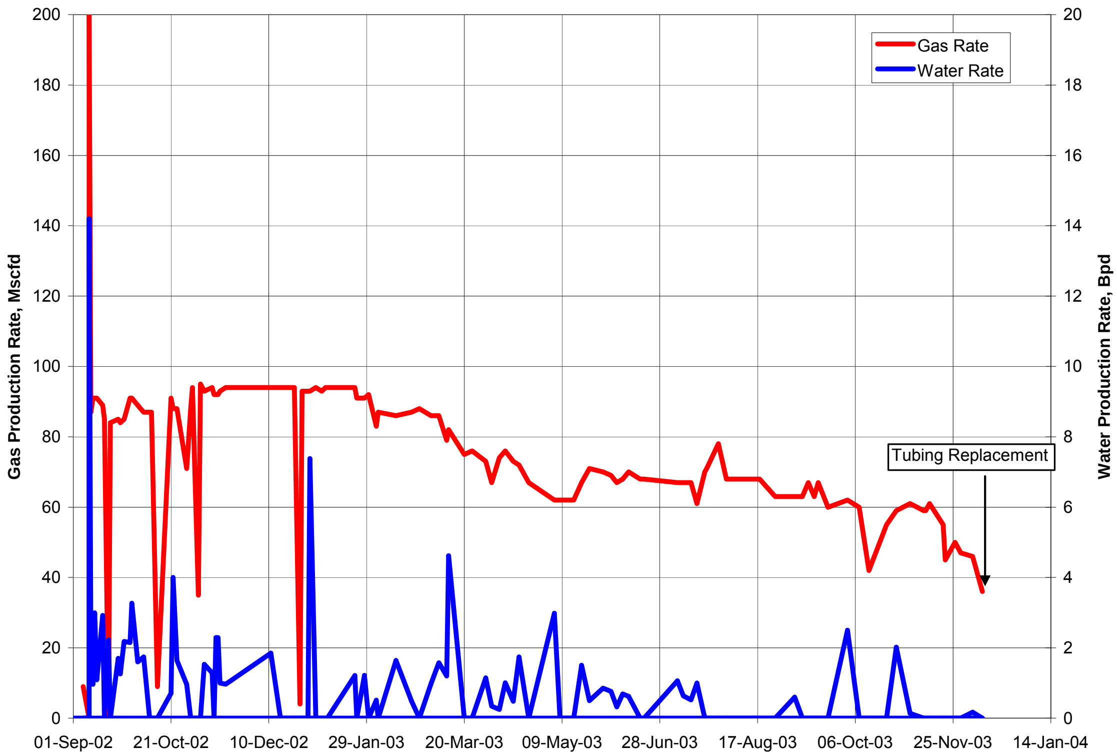


Figure 15 – Rigging-up Flexible Tubing Spool

connecting the two sections of the flexible velocity string (**Figure 16**). Depth was approximated using a sand line and depthometer.

At a depth of approx 2,400 feet, the tubing began an uncontrolled spool-off into the well, whereby an unknown amount of tubing ran into the well (estimated at 200 feet) before the tubing stopped by itself. It is determined that the tubing became detached from the wooden spool, allowing it to spin off of the spool without any breaking action.

So, tubing slips were set at wellhead to secure tubing in the well and the remaining tubing was spooled-off (approximately 2,500 feet) and laid on the ground (**Figure 17**). The tubing was reattached to the end of the wooden spool, re-wound, and then run into the well. From subtraction of the remaining product length on site, the final length of the installed velocity string was determined to be 5,607 feet.

Figure 16 – Tubing Splice

Figure 17 – Laying Down the Velocity String

Production Monitoring
The well was placed on production immediately following the installation of the *Thermoflex* velocity string and the production monitored. **Figures 18 and 19** depict the production and pressure behavior for the TMR8 well.

Anecdotal reports from the operator within the well's first week of velocity tubing production indicated that the well was producing about 50 Mscf/d on a constrained pressure of approximately 135 psig, with the well producing trace amounts of liquid. The constrained condition was then removed, which was expected to result in a gas production rate of about 80 Mcf/d. This gas production rate would be in excess of the well's pre-replacement gas rate.

Once the well began producing in an unrestricted fashion, tubing pressure declined to line pressure (85 psig) and the gas rate was determined to be approximately 60 Mcf/d, with no liquid production. With the decline in tubing pressure, it was noted that the casing pressure was increasing. **Figure 19** exhibits this behavior over a time period of several months. Further, the well, although still producing gas at a reduced rate, was no longer producing reservoir liquids, indicating that 1) the tubing was possibly being choked-back by fluids in the surface lines, or 2) there was a restriction to flow in the wellhead assembly and/or tubing string.

In late January, field operations were conducted in an attempt to remediate the TMR8 production difficulties. First, all surface lines were blown down back to the wellhead, where approximately 5 gallons of water was collected. Subsequent operations included the placement of about 3 gallons of methanol down the tubing to eradicate any hydrate blockage near the surface. Field observation following these procedures indicated nearly an immediate equalization of tubing and casing pressures. However, over the next several weeks of production, the well did not produce liquids nor did the tubing and casing pressures remain near-equalized as the casing pressure again increased over that of the tubing and the well continued to under-perform.

To mitigate the abnormally high casing pressure, the operator installed a pressure regulator on the annulus. This installation helped reduce the casing string pressure by selling-off the annular gas. While this did reduce casing pressure, gas and liquid production was not enhanced.

Recently, the wellhead assembly was broken down and inspected. The operator was able to detect an obstruction within the top of the tubing string, indicating at least partial blockage to gas flow. Plans to remediate and/or remove this blockage to encourage natural production are currently underway and will be based on the nature of blockage present.

Figure 18 – TMR8 Production History

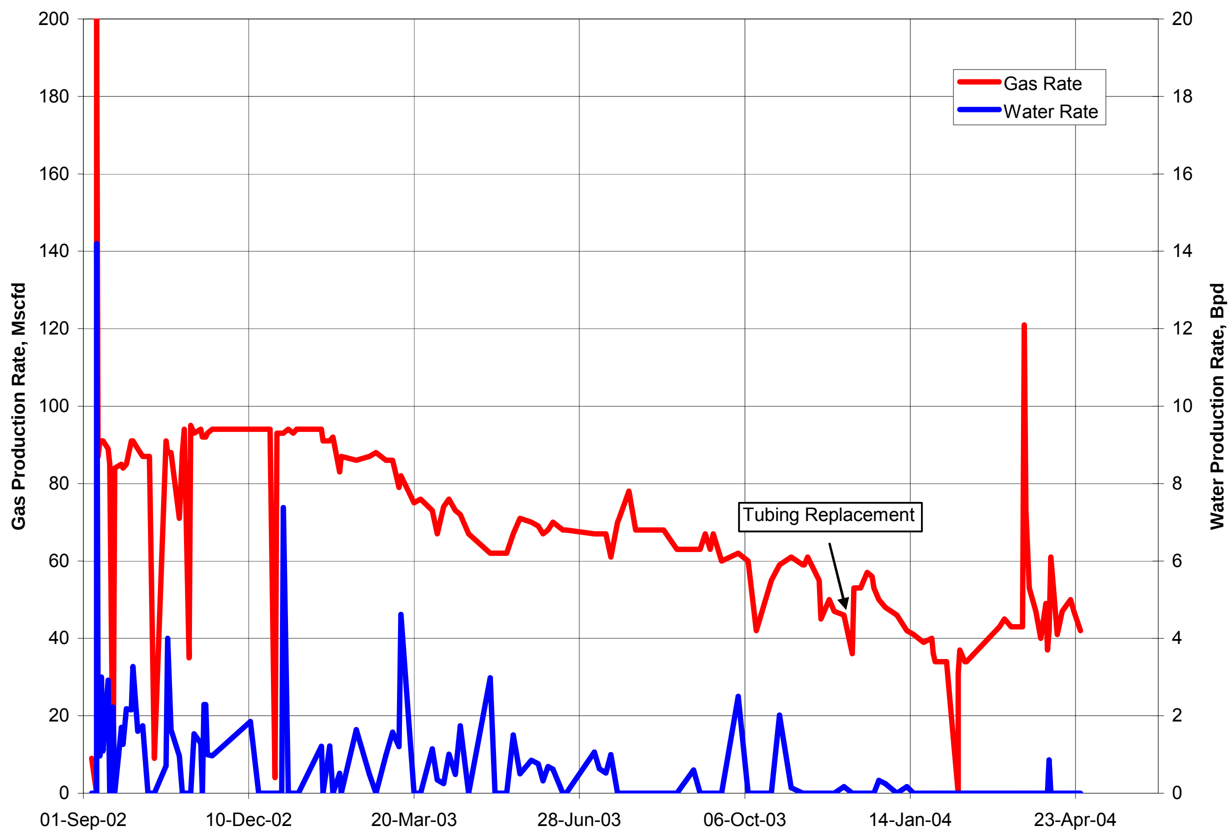
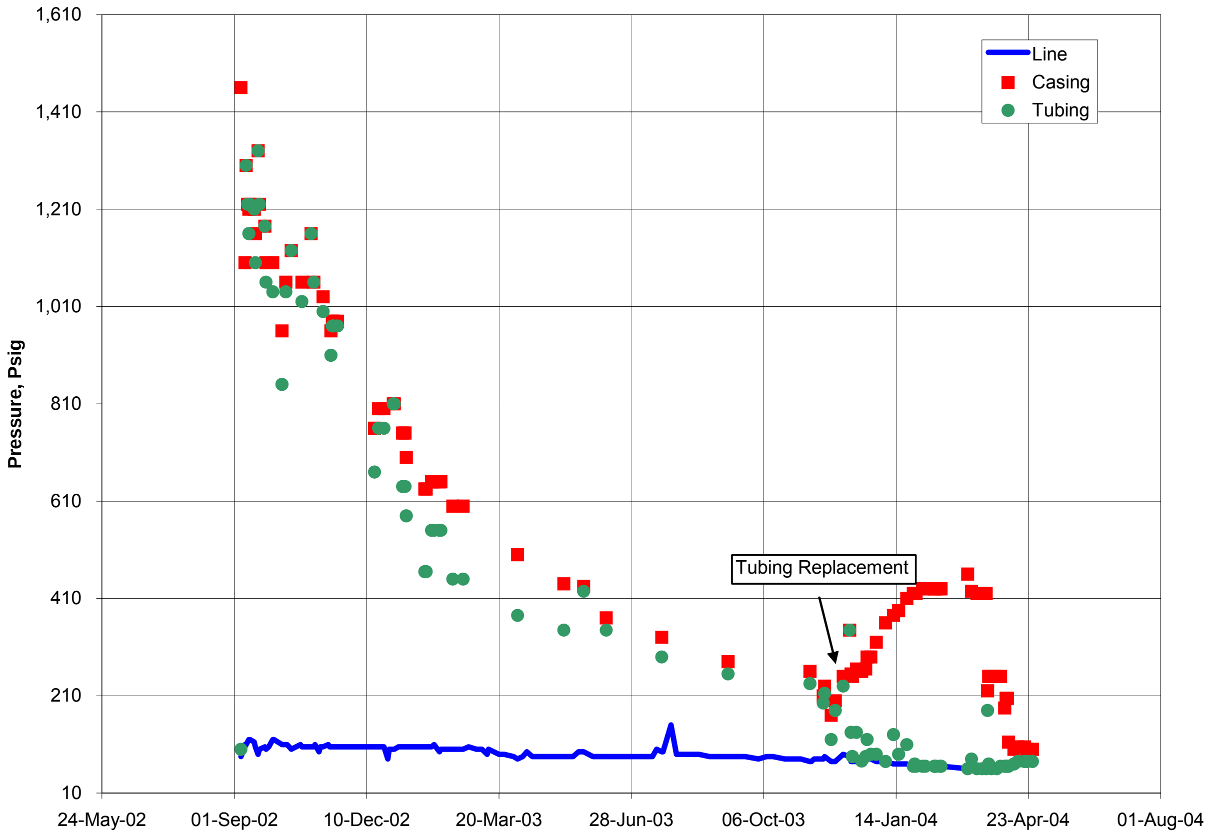


Figure 19 – TMR8 Pressure History



Conclusions

- The project generated liquid lifting performance charts using both Turner's (spherical droplet) and Li's (flat-droplet) formulations. A Microsoft Excel spreadsheet is included for the computation of flat-droplet terminal velocity and critical rates.

- Liquid droplet shape can have a large impact on the terminal rate calculation. Since the drag coefficient is highly dependent upon the particle, calibration of the correct critical rate values to field observations is a necessary step when under taken a similar study.

- The use of surface conditions to determine terminal velocities and then critical rates is an acceptable practice for tubing-completed wells, providing the tubing is set to perforations.

- Tubing providers have on hand, for the most part, tubing sizes in the range of 1 to 3 inches. However, little/no roughness information exists for aid in the determination of friction pressure drop.

- When computation of downhole pressure drop is necessary, formulations by Hagedorn and Brown were found to be the most precise.

- Frictional pressure drop can be greatly reduced through the use of lower-cost, higher-strength plastic (smooth) pipes. These low-friction tubulars are best applied in shallower applications.

- Turbulence damping was also found to reduce friction, suggesting a high-strength seam on the inside of tubulars may be beneficial.

Acknowledgements

Advanced Resources International, Inc. would like to thank Great Lakes Energy Partners, LLC., the project's industry partner, for initially seeing the value of this work and agreeing to provide a suitable test site in the Cooperstown gas field. The Great Lakes staff was always willing to provide time, data and guidance to the project.

Additionally, ARI would like to thank Mr. Peter Han of Honeywell, Inc., Mr. John Holko of Lenape Resources and Mr. Robert Gleim from PolyFlow for donating time, materials and efforts for the installation of the *Thermoflex* velocity string.

Finally, the project team would like to thank the Stripper Well Consortium for seeing merit in this work and providing funding through the United States Department of Energy and the State of New York.

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List of Acronyms, Abbreviations and Symbols

v_t	terminal velocity (ft/sec)
σ	surface tension (dynes/cm)
ρ	density (lb mass/ft^3)
A	flow area of conduit (ft^2)
C_d	drag coefficient (dimensionless)
p	pressure (psia)
q_c	critical rate (MMscf/D)
T	temperature (^{o}R)
z	gas compressibility factor

List of Conversions

1 dyne/cm = 7.376E-05 lbf/ft

Appendix A

Tubing Supplier Contact List

Name	Address	City	State	Phone	Website	Email
Consolidated Pipe & Supply	1205 Hilltop Pkwy, Birmingham, AL 35204 (Var. Locs.)	Birmingham	AL	205-323-7261		
Smith Fiberglass Products, Inc.	2700 W. 65th St., Little Rock, AR 72209	Little Rock	AR	501-568-4010	www.aosmith.com/sfp	jbrummet@aosmith.com
American Pipe and Tubing Co.	2157 Mowawk, Bakersfield CA 93308	Bakersfield	CA	805-323-0343		
BST Lift Systems	1604 Morse Ave., Ventura CA 93003	Ventura	CA	805-654-1696		kelley@west.net
Bakersfield Pipe & Supply, Inc.	2903 Patton Way, Bakersfield, CA 93308	Bakersfield	CA	805-589-9141		
Equipment & Material Exchange, Inc.	P.O. Box 246, Taft, CA 93268	Taft	CA	805-763-1323	www.usedeq.com	usedeq@usedeq.com
Independent Pipe & Steel, Inc.	P.O. Box 2422, Bakersfield, CA 93303	Bakersfield	CA	805-325-0398		
Keenan O.C.T.	One World Trade Center, #450, Long Beach, CA 90831	Long Beach	CA	562-495-6396		
Kelly Pipe Co.	11700 Bloomfield Ave., Santa Fe Springs, CA 90670	Santa Fe Springs	CA	310-868-0456	www.kellypipe.com	sales@kellypipe.com
Mill Man Steel Inc.	7901 E. Bellview Ave. #215, Englewood, CO 80111 (other locs)	Englewood	CA	1-800-748-2928		
National Pipe & Casing Corp.	9615 S. Norwalk Blvd., #200, Santa Fe Springs, CA 90670	Santa Fe Springs	CA	310-699-9900		
Polyethylene Piping of California, Inc.	7501 Downing Ave., Bakersfield, CA 93308	Bakersfield	CA	805-589-8223		
Seaboard Tubular Products	3333 S. Malt Ave., Los Angeles, CA 90040	Los Angeles	CA	818-330-2888		
State Pipe & Supply Co.	9615 S. Norwalk Blvd., Santa Fe Springs, CA 90670	Santa Fe Springs	CA	310-695-5555		
Sumitomo Corp. Of America	444 S. Flower St., Suite 4800, Los Angeles, CA 90071	Los Angeles	CA	213-627-4783		
Tubular Sales & Equipment Inc.	3003 Fairhaven Dr., Suite C, Bakersfield, CA 93308	Bakersfield	CA	805-328-5510		
Tubesales	2211 Tubeway, Los Angeles, CA 90040 (also TX and LA)	Los Angeles	CA	213-728-9101		
Jensco Pipe & Equipment, Inc.	5524 S. Jasper Way, Aurora CO 80015	Aurora	CO	303-766-9164		
Ipsco Tubulars Inc.	2011 Seventh Ave, Camanche, IA 52730	Camanche	IA	319-242-0000		
IPSCO Tubulars, Inc.	2011 Seventh Ave., Camanche, IA 52730	Camanche	IA	319-242-0000		
Leavitt Tube	1717 W. 115th St., Chicago, IL 60643	Chicago	IL	1-800-532-8488		
Midwest Pipe, Inc.	800 W. High St., Olney, IL 62450	Olney	IL	618-392-0666		
Plexco (Div of Chevron Chemical Co.)	1050 IL Rt. 83, Suite 200, Bensenville, IL 60106	Bensenville	IL	630-350-3728	www.plexco.com	info@plexco.com
Cresline Plastic Pipe	955 Diamond Ave. Evansville, IN 47711	Evansville	IN	812-428-9300		
Kramer Oilfield Service	P.O. Box 646, Wellsville, KS 66092	Wellsville	KS	913-883-4871		
RAS Oilfield Supplies, Inc.	R R 3, Box 15, Eureka, KS	Eureka	KS	316-583-7496		
Wichita Valve & Fitting Co.	326 Wabash, Suite 1, Wichita, KS 67214	Wichita	KS	316-262-6111		
BWI Pipe & Supply	616 S. Columbia St., Albany, KY 42602	Albany	KY	606-387-6411		
Glasgow Well Supply	251 Kentucky St., Glasgow, KY 42141-1650	Glasgow	KY	502-651-6101		
Newport Steel Corp.	9th & Lowell Sts., Newport, KY 41072	Newport	KY	606-292-6804		
Aztec Pipe Inc.	920 W. Pinhook Road Ste 240, Lafayette, LA 70503	Lafayette	LA	318-233-4990		
Blowout Tools Inc (Coiled)	P.O. Box 32121, Lafayette, LA 70593	Lafayette	LA	318-264-1098		
Ferguson Pipe & Supply	305 Friedrichs Ave., Metairie, LA 70005	Metairie	LA	504-833-0633		
51 Oil Corp.	3227 Hwy 90 E., Broussard, LA 70518	Broussard	LA	318-234-2264		
Martin Oil Country Tubular Inc.	4209 Cameron St., Lafayette, LA 70506	Lafayette	LA	318-233-7036		
Midland Pipe Corp.	3636 N. Causeway Blvd., #300, Metairie, LA 70002	Metairie	LA	504-837-5766		
Norman & Associates (Macaroni)	613 N. 5th St., West Monroe, LA 71291	West Monroe	LA	318-325-4315		
Pellerin's Tubular Service Inc.	Hwy 14 W, New Iberia, LA 70560	New Iberia	LA	318-365-1033		
Tube-Alloy Corp.	3106 Grand Cailou Rd., Houma, LA 70363	Houma	LA	504-876-2886		

Name	Address	City	State	Phone	Website	Email
Pipe & Piling Supplies (USA)	244 Kincheloe Road, Kincheloe, MI 49788	Kincheloe	MI	906-495-2245	www.pipe_piling.com	
Standard Stanchion & Pipe Supply	2149 Fyke Dr., Milford, MI 48381	Milford	MI	248-684-4100		
Tubular Steel, Inc.	1031 Executive Pkwy., St. Louis, MO 63141	St. Louis	MO	314-851-9200	www.tubularsteel.com	info@tubularsteel.com
Trident Steel Corp.	1000 Des Peres Rd., Suite 116, St. Louis, MO 63131	St. Louis	MO	314-822-0500		
St. Louis Pipe & Supply	16321 Westwoods Bus. Park, Ellisville, MO 63021	Ellisville	MO	314-391-2500		
Victor Pipe & Steel, Inc.	Hwy. 79 N, Winfield, MO 63389	Winfield	MO	1-800-264-6315		
Lockett Pipe Company, Inc.	2812 First Ave. N., Suite 401, Billings, MT 59101	Billings	MT	1-800-927-4731	www.mcn.net/~lockett	lockett@mcn.net
Redlon and Johnson	200 Gay St., Manchester, NH 03103 (various locations in ME)	Manchester	NH	603-669-8100		
Hoke, Inc.	One Tenakill Park, Cresskill, NJ 07626	Cresskill	NJ	201-568-9100		
Caprock Pipe and Supply	P.O Box 1535, Lovington, NM 88260	Lovington	NM	505-396-5881		
Milford Pipe and Supply, Inc.	1224 W. Broadway Pl, Hobbs, NM 88240 (also Odessa TX)	Hobbs	NM	505-397-6400		
AST USA Inc.	10 Bank St., White Plains NY, 10606	White Plains	NY	914-428-6010		
LTV Steel Tubular Products Co.	1315 Albert St., Youngstown, OH 44501	Youngstown	OH	1-800-445-7473		
RMI Titanium Company	1000 Warren Ave., Niles, OH 44446	Niles	OH	330-544-7633		
The Swagelok Companies	31400 Aurora Road, Solon, OH 44139 (other locations)	Solon	OH	216-349-5934	www.swagelok.com	
Red Man Pipe & Supply Co.	8023 E. 63rd Pl., Suite 800, Tulsa OK 74133	Tulsa	OK	918-250-8541		
Performance Pipe Corp.	513 Boren Blvd., Seminole, OK 74868	Seminole	OK	405-382-3522		
Pipe Source Co.	304 Callahan, Muskogee, OK 74402	Muskogee	OK	918-682-0940		
Steel Service Oilfield Tubular	4200 E. Skelly Dr., Suite 620, Tulsa, OK 74135	Tulsa	OK	918-495-1420		
Arvine Pipe & Supply Co., Inc.	1708 Topeka Dr., Norman, OK 73069	Norman	OK	405-364-1950		
Bethlehem Pipe Sales Inc.	2651 E. 21st St., Suite 501, Tulsa, OK 74114	Tulsa	OK	918-745-2212		
C & Y Casing Pulling, Inc.	250 S. Eastland Dr., Duncan, OK 73534	Duncan	OK	405-255-4453		
Erlanger Tubular Corp.	5610 Bird Creek Ave., Catoosa, OK 74015	Catoosa	OK	918-266-3970		
Keefer Oil Co.	131 E. Cottage, Ada, OK 74820	Ada	OK	405-332-0395		
Lillard Pipe & Supply, Inc.	177 S. Benson Park Rd., Shawnee, OK 74801	Shawnee	OK	405-273-6200		
Spartan Steel Products	1032 W. Main, Suite 200, Duncan, OK 73533	Duncan	OK	1-888-373-7675		ssproducing@aol.com
Vantuyl & Fairbank Inc.	394 Station St., Petrolia, ON N0N 1R0, Canada	Petrolia	ON	519-882-0230		
Armco Inc.	P.O. Box 11, Sharon PA	Sharon	PA	412-347-7771		
Crispin-Multiplex	600 Fowler Ave, Berwick, PA 18603	Berwick	PA	1-800-247-8258		
Damascus Bishop Tube Co., Inc.	795 Reynolds Industrial Park Rd. Greenville, PA 16125	Greenville	PA	724-646-1500		
Energy Products Co.	P.O. Box 809, McMurray, PA 15317	McMurray	PA	412-942-1000		energyprod@earthlink.net
Hajoca Corp.	127 Coulter Ave., Ardmore, PA 19003	Ardmore	PA	610-649-1430		
Interstate Pipe & Supply Co	P.O. Box 215, Clintonville, PA 16372	Clintonville	PA	814-385-6633		
Koppel Steel Corp.	PO Box 750, Beaver Falls, PA 15010	Beaver Falls	PA	1-800-992-3702	www.koppelsteel.com	sales@koppelsteel.com
Petroleum Pipe & Supply Co.	Industry Way, Carnegie, PA 15106	Carnegie	PA	412-279-7710		
Sandvik Steel Co.	982 Griffin Pind Rd., Scranton, PA 18411	Scranton	PA	717-587-5191		
Foster, L. B., Co.	415 Holiday Dr., Pittsburgh, PA 15220 (TX and GA also)	Pittsburgh	PA	412-928-3400	www.lbfoster.com	dseybert@ix.netcom.com
Dresser Oil Tools	4949 Joseph Hardin Dr., Dallas, TX 75236	Dallas	TX	214-331-3313		
Joy Pipe USA, LLC.	16225 Park 10 Pl. Dr., #400, Houston, TX 77084	Houston	TX	281-579-0388	www.joypipe.com	info@joypipe.com
Maverick Tube Corp.	15333 JFK Blvd., Suite 160, Houston, TX 77032	Houston	TX	281-442-1093		
Phillips Driscopipe	2929 N. Central Expwy., #300, Richardson TX 75083	Richardson	TX	214-783-2666	www.phillips66.com	
Pipe & Tube Supplies Inc.	4201 W. Orange St, Pearland, TX 77581	Pearland	TX	281-485-3133		
Van Leeuwen Pipe and Tube Inc.	15333 Hempstead Road, Houston, TX 77404 (various locations)	Houston	TX	713-466-9966		
Star Fiber Glass Systems, Inc.	2425 S.W. 36th St., San Antonio, TX 78237	San Antonio	TX	210-434-5043	www.onr.com/star/	
Abbot's Oilfield Supply, Inc.	1151 W. Second, Odessa, TX 79763	Odessa	TX	915-337-7335		
Adler Pipe Co.	7414 Leopard, Corpus Christi, TX 78409	Corpus Christi	TX	512-289-6607		
Alloy Tubular Products Co.	P.O. Box 910, Channelview, TX 77530	Channelview	TX	713-457-1280		
Algoma Tube Corp.	800 Gessner, Suite 290, Houston, TX 77024	Houston	TX	713-465-8998	www.algoma.com	

Name	Address	City	State	Phone	Website	Email
Bays Oilfield Supply Co. Inc.	P.O. Box 753499, Dallas, TX 75275	Dallas	TX	405-235-2297		
Bellville Tube Corp.	P.O. Box 220, Bellville, TX 77418	Bellville	TX	409-865-9111		
Bob Beck Tubulars	P.O. Box 9726, Midland, TX 79708	Midland	TX	915-682-3131		
Bourland & Leverich Supply Inc.	P.O. Box 778, Pampa, TX 791065 (various locs, TX, OK, CO)	Pampa	TX	806-665-0061		
BTS Limited Inc.	13164 Memorial Dr. #120, Houston TX, 77079	Houston	TX	713-461-6760		rbaron3810@aol.com
Bunker Steel Corp.	800 Bering Dr. Suite 340, Houston, TX 77057	Houston	TX	713-789-8750		
Carbide Blast Joints, Inc.	21283 Foster Road, Spring TX 77388	Spring	TX	713-353-6750		
Centron International, Inc.	600 FM 1195 S., Mineral Wells, TX 76068	Houston	TX	940-325-1341		centron@eastland.net
Champions Pipe & Supply Inc.	952 Echo Lane, Suite 200, Houston, TX 77024	Houston	TX	713-468-6555		
Chichasaw Distributors Inc.	800 Bering Dr. Suite 330, Houston, TX 77057	Houston	TX	713-974-2905		chickasaw@attmail.com
Cinco Pipe & Supply Inc.	1601 Welch, Houston, TX 77006	Houston	TX	713-658-0700		
Colorado Tubulars Company	2121 W. Spring Creek Pkwy, Suite 232, Plano, TX 75023	Plano	TX	972-491-5590		
Conestoga Supply Corp.	15915 Katy Frwy, Suite 600, Houston TX 77094	Houston	TX	281-579-8811		
Cressman Tubular Products Corp.	3939 Belt Line Rd., #360-20, Dallas, TX 75244	Dallas	TX	214-352-5252		
CSI Steel & Supply Co.	South Houston, TX 77587	South Houston	TX	281-997-8340		
East & Associates, Inc.	P.O. Box 691566, Houston, TX 77269	Houston	TX	713-580-3363		
Fiberglass Systems LP	2425 S. W. 36th St., San Antonio, TX 78237	San Antonio	TX	210-434-5043		
Gulf Coast Pipe, Inx.	P.O. Box 1335, Pearland, TX 77588	Pearland	TX	281-992-6700		
Holiday Pipe Co.	P.O Box 6529, Pasadena, TX 77506	Pasadena	TX	713-475-9044		
Klockner Steel Trade	1800 St. James Pl., Suite 603, Houston, TX 77056	Houston	TX	713-627-7310		
Kurvers Inc.	1500 S. Dairy Ashford, Suite 444, Houston, TX 77077	Houston	TX	281-496-3375		kurversusa@kurvers.com
Kyser Co.	2019 McKenzie, Suite 150, Carrollton, TX 75006 (other TX Locs)	Carrollton	TX	972-488-1811		
Marubeni Tubulars, Inc.	7500 San Felipe, Suite 950, Houston TX 77063	Houston	TX	713-780-5600		
Master Tubulars, Inc.	24 Smith Rd., Suite 250, Midland, TX 79705	Midland	TX	915-682-8996		
Maverick Tube Corp.	15333 JFK Blvd., Suite 160, Houston, TX 77032	Houston	TX	281-442-1093		
MC Tubular Products, Inc.	580 Westlake Park Blvd., #1610, Houston TX 77079	Houston	TX	281-870-1212		
McEvoy, Mike Companies, Inc.	1800 Augusta, Suite 212, Houston, TX 77057	Houston	TX	713-783-0517		
Mitsui Tubular Products Inc.	1000 Louisiana, Suite 5700, Houston, TX 77002	Houston	TX	713-236-6160		
Moore, Wayne Pipe & Supply Co.	Anson Hwy., Abilene, TX 79604	Abilene	TX	915-673-5732		
M W Commodities	20214 Braidwood Dr. Ste 160, Katy, TX 77450	Katy	TX	281-492-1415		
Padre Tubular Inc.	711 N. Carancahua, #1102, Corpus Christi, TX 78475	Corpus Christi	TX	512-887-0861		
PK Pipe & Tubing Inc.	P.O. Box 2470, Uvalde, TX 78802	Uvalde	TX	830-278-6606		
Posey Pipe & Equipment, Inc.	P.O. Box 10172, Midland, TX 79702	Midland	TX	915-685-3447		
Pyramid Tubular Products, Inc.	2 Northpoint Dr. Suite 610, Houston, TX 77060	Houston	TX	281-405-8090		
Reliable Tubular & Supply, Inc.	2601 E. I-20, Midland, TX 79704	Midland	TX	915-684-8488		
Sabine Pipe & Supply Co. Inc.	1900 Industrial Blvd., Kilgore, TX 75662	Kilgore	TX	903-984-3094		
SIM-TEX, Inc.	12605 E. Frwy., Suite 103, Houston, TX 77015	Houston	TX	713-450-3940		
S.I.W. Pipe & Supply, Inc.	6149 W. 10th, Odessa, TX 79769	Odessa	TX	915-381-0501		
South Star Oil Field Equipment	410 W. First, Odessa, TX 79760	Odessa	TX	915-335-0602		
S & S Pipe & Supply Co.	3112 Pleasant Green, Victoria, TX 77901	Victoria	TX	512-573-4322		
System Pipe & Supply Inc.	6211 W. N.W. Hwy., Suite 253D, Dallas, TX 75225	Dallas	TX	214-692-0100		
Texas Tubular Products	FM 250, P.O. Box 0388, Lonestar, TX 75668	Lonestar	TX	903-639-2511		
Tex-Isle Supply Inc.	10830 Old Katy Rd., Houston, TX 77024	Houston	TX	713-461-1012		
Triad Pipe & Steel Company	9225 Katy Frwy., Suite 102, Houston, TX 77024	Houston	TX	713-467-5242		
Tubular Corp. of America	363 N. Sam Houston Pkwy. E., Suite 1660, Houston TX 77060	Houston	TX	281-774-3500		

Name	Address	City	State	Phone	Website	Email
Vallourec & Mannessmann Tubes Corp.	1990 Post Oak Blvd., Suite 1400, Houston, TX 77056	Houston	TX	713-479-3200		
Vallourec, Inc.	1990 Post Oak Blvd., Suite 710, Houston, TX 77056	Houston	TX	713-961-2468		valloure@vallourec_inc.com
Vantage Tubulars, Inc.	701 N. Post Oak Road, Suite 220, Houston, TX 77024	Houston	TX	713-683-7232		
Wilson Industries, Inc.	1301 Conti, Houston TX 77002	Houston	TX	713-237-3700		
American Protectors, Inc.	3407 Dalworth, Arlington, TX 76011	Arlington	TX	817-649-8843		
Ameron International Fiberglass Pipe Div.	5300 Hollister, Suite 111, Houston, TX 77040	Houston	TX	713-690-7777		
Cinco Pipe & Supply Inc.	1601 Welch, Houston, TX 77006	Houston	TX	713-658-0700		cpipe@swbell.net
Davis, Paul Pipe & Supply	P.O. Box 6112, Abilene, TX 79608	Abilene	TX	915-698-2293		
Vinson Supply Company	Two Northpoint, Suite 500, Houston, TX 77060	Houston	TX	1-800-877-2636	www.tubulars.com	
Wing Pipe & Supply	6440 N. Central Expwy., LB6, -#300, Dallas, TX 75206	Dallas	TX	214-750-8888		
Dependable Pipe and Supply Co.	Rt. 33 E, Box 606, Spencer WV 25276	Spencer	WV	304-927-1660		
Bock Specialties Inc.	P.O. Box 2880, Mills, WY 82644	Mills	WY	307-237-2207		
Grinnell Supply Sales Co.	Various Locations	Various Locations				
Marmon/Keystone Corporation	Various Locations, USA and Canada	Various Locations		724-283-3000	www.marmonkeystone.com	
The Panila Group of Companies, Inc.	1165 J 44 Ave. S.E., Calgary, AB T2G 4X4, Canada	Calgary	AB	403-243-7930		
Prudential Steel, Ltd.	P.O. Box 1510, Calgary, AB T2P 2L6, Canada	Calgary	AB	403-267-0300	www.prudentialsteel.com	info@prudentialsteel.com
Oil Pro Oilfield Production Equip. LTD.	1230, 630 6th Ave. S.W., Calgary, AB T2P 2Y5, Canada	Calgary	AB	403-215-3373		

Appendix B

Annotated Literature Review

Duggan, J., "Estimating Flow Rates Required to Keep Gas Wells Unloaded," **SPE No. 32**, Journal of Petroleum Technology, December 1961, pp. 1173-1176.

Created a chart to showing the minimum flow rate required to keep condensate gas wells unloaded at a linear velocity of 5 ft/sec (wellhead).

Observed from field data that a wellhead velocity of about 5 ft/sec is necessary to keep condensate wells unloaded.

With available data, a negligible effect was seen between unloading wellhead velocities of lean and rich condensates.

v = q*T / (5.898*A*ptf)

where, v = linear velocity, ft/sec
q = well volume, mscfd
ptf = wellhead flowing pressure, psia
A = cross-sectional area, ft2
T = WHT/520 Rankin, dimensionless

A velocity of 5 ft/sec may not be necessary to keep a (condensate) well on production if the wellhead flowing pressure is sufficiently above the delivery pressure. Some unpublished tests indicate that a well can sustain production in small diameter tubing at velocities as low as 3 ft/sec if the unloading flowing wellhead pressure is at least 300 psig above the line pressure.

Included data table of condensate well tests.

Gaither, O., Winkler, H., Kirkpatrick, C., "Single- and Two-Phase Flow in Small Vertical Conduits Including Annular Configurations," **SPE No. 441**, Presented at the 37th Annual SPE Fall Meeting, October 7-10, 1962, Los Angeles, CA.

Showed that certain existing two-phase fluid pressure drop correlations, when applied to the gas water mixture investigated in this study, cannot be extended to small conduits.

Darcy friction = 4*fanning friction,

Experimentally derived two-phase (gas-water) data tables for 1, 1.25 and 1 X 2 in tubing are presented.

New correlating parameters are given which, when properly applied, should prove valid for most fluid mixture systems.

Hagedorn, A., Brown, K., "Experimental Study of Pressure Gradients Occurring During Two-Phase Flow in Small Diameter Vertical Conduits," **SPE No. 940**, Presented at the 39th Annual SPE Fall Meeting, October 11-14, 1964, Houston, TX.

Studied the pressure gradients occurring during continuous two-phase flow through 1, 1.25 and 1.5 inch (nominal) diameter tubing over a 1,500 feet vertical distance.

In contrast to single-phase flow, the pressure losses in multiphase flow do not always increase with a decrease in the size of the conduit or an increase in the production rate. This is attributed to the presence of the gas phase that tends to slip by the liquid phase without actually contributing to its lift.

Relative roughness is accounted for, although the effect for two-phase flow is very small (referenced another author).

Included dimensionless correlations.

Orkiszewski, J., "Predicting Two-Phase Pressure Drops in Vertical Pipe," **SPE No. 1546**, Presented at the 41st Annual SPE Fall Meeting, October 2-5, 1966, Dallas, TX.

Data from 22 Venezuelan heavy oil wells presented and used in addition to data provided by Poettmann and Carpenter, Baxendell and Thomas, Fancher and Brown, and Hagendom and Brown to yield a total of 148 data points for the study.

Uses a modified Griffin-Wallis correlation with a standard deviation of about 10% (error in pressure drop computation).

Method outperformed Duns and Ros and Hagedorn and Brown methods.

Appendix A contains the description of the model.

Appendix D contains an example calculation.

Turner, R., Hubbard, M., Dukler, A., "Analysis and Prediction of Minimum Flow Rates for the Continuous Removal of Liquids from Gas Wells," **SPE No. 2198**, Presented at the 43rd Annual SPE Fall Meeting, September 29 - October 2, 1968, Houston, TX.

Identifies the existence of two proposed physical models for the removal of gas well liquids: (1) liquid film movement along the walls of the pipe and (2) liquid droplets entrained in the high velocity gas core.

The film model is outlined in Appendix A.

The larger the drop, the higher the gas flow rate necessary to remove it.

vt = 17.6*(surf tens)^ .25*(rho,l - rho,g)^.25 / rho,^0.5
where, vt = terminal velocity of free falling particle, ft/sec surf
tens = surface tension, dynes/cm
rho,g = gas density, Ibm/cu ft
rho,l = liquid density, Ibm/cu ft

A 20% upward adjustment was made to correct the data.

Wellhead conditions tended to control the study and the droplet removal was found to be the limiting liquid removal mechanism.

Surface tension measurements are 20 dynes/cm for condensate and 60 dynes/cm for water while density values were 45 Ibm/cu ft for condensate and 67 Ibm/cu ft for water, respectively.

qg = 3.06*p*v*A/(T*z)
where, qg = gas rate, MMscfd
p = pressure, psia
v = velocity, ft/sec
A = cross sectional area, sq ft T =temperature, R
z = gas deviation factor

Determination of minimum necessary flow rates by the determination of the flow rate that will remove the largest drops of liquid, calculated using particle and drop break-up mechanics. **However, the equation was adjusted upward by 20% to match data.**

The gas-liquid ratio does not influence the minimum lifting velocity in the observed ranges of liquid production up to 130 bbl/MMscf.

Tek, M., Gould, T., Katz, D., "Steady and Unsteady-State Lifting Performance of Gas Wells Unloading Produced or Accumulated Fluids," **SPE No. 2552**, Presented at the 44th Annual SPE Fall Meeting, September 28 - October 1, 1969, Denver, CO.

The authors introduce the concept of lifting potential, which relate the characteristics of two-phase flow to the mechanics of flow through the porous media.

Includes a series of plots relating lifting potential to depth, WHP, BHP, etc.

Hutlas, E., Granberry, W., "A Practical Approach to Removing Gas Well Liquids," **SPE No. 3473**, Presented at the 46th Annual SPE Fall Meeting, October 3-6, 1971, New Orleans, LA.

Discussed history of loaded fluid removal in Kansas' Hugoton Gas Field.

Three "best current methods" of liquids removal are pumping units, liquid diverters and gas lift, and 1 inch tubing strings.

Run 1 inch tubing inside the production string (2-3/8 inch) to produce gas and liquids. Amoco had ten such installations at the time of this paper - four successfully doubled flow rate.

Economics of a system are evaluated using stabilized backpressure curve, requiring stabilized flow rate, flowing bottomhole pressure, static reservoir pressure and the slope of the backpressure curve.

Libson, T., Henry, J., "Case Histories: Identification of and Remedial Action for Liquid Loading in Gas Wells - Intermediate Shelf Gas Play," SPE No. 7467, Presented at the 53rd Annual SPE Fall Meeting, October 1-4, 1978, Houston, TX.

This paper discusses how liquid loading in gas wells inhibited gas production in the Intermediate Shelf gas play in southwest Texas. Actual case histories are used to illustrate how to identify and remedy liquid loading in low-volume gas wells. Methods such as plunger lift, beam pump, small-ID tubing, foam injection, and flow controllers are discussed and illustrated.

Critical velocities were found to be close to 1,000 ft/min (16.7 ft/sec).

Casing pressures reflecting more than a 200 psig differential above flowing tubing pressure generally was indicative of excessive liquid accumulation.

The depth at which the critical flow rate becomes important is at the surface.

Beam pumps were moderately successful, plunger lifts increased productivity by an average of 20 Mscfd, smaller tubing (1.9" OD, 1.61" ID) increased gas production by 50 Mscfd.

Field plans included wells producing >340 Mscfd that declined to 154<rate<340 Mscfd would receive small tubing and wells in the 154<rate<340 Mscfd range would be put on plunger lift or soap injection. Field-wide rotation of the smaller tubing would be enacted for those wells producing less than 154 Mscfd.

MacDonald, R., "Fluid Loading in Low Permeability Gas Wells in the Cotton Valley Sands of East Texas," **SPE No. 9855**, Presented at the 1981 SPE/DOE Low Permeability Symposium, May 27-29, Denver, CO.

A modified calculation procedure, based on actual flow data, for the determination of fluid loading is presented.

Perm ranges from .01 to .001 and and porosity from 0 to 10%. BHT and BHP average 265F and 4600 psig, respectively. Depth is about 10,000 ft. Gross thickness is 1,400 ft. Average production characteristics are a 0.63 gravity gas, a 55 API condensate and 75 bbl/MMcf of water.

A Newtonian fluid (spherical) with a Reynolds number between 1,000 and 200,000 has a drag coefficient equal to 0.44.

Included is a table with a 5-well response to compression (900 psi FTP to about 130 psi FTP). One well received 1.315" OD tbg prior to compression and was in an unloaded state.

Greene, W., "Analyzing the Performance of Gas Wells," **SPE No. 10743**, Presented at the 1982 SPE California Regional Meeting, March 24-26, San Francisco, CA.

The author defines inflow, outflow and tubing performance curves.

Inflow performance computations conducted using the Russel, et. al. method.

The outflow performance of a completely dry gas well will have not apex (flowpoint). At a zero flow rate, the vertical difference between the two performance curves represents the static weight of the dry gas column in the tubing string.

Although tubing performance curves are useful, the author prefers outflow and inflow curves.

Lea, J., Tighe, R., "Gas Well Operations with Liquid Production," **SPE No. 11583**, Presented at the 1983 Production Operations Symposium, February 27 - March 1, Oklahoma City, OK.

The author sets forth the pertinent engineering considerations and production options the engineer has in dealing with the determination of liquid loading.

Increases critical velocity by 20%, likeTurner.

Determines that Turner's method should be used in conjunction with a pressure drop correlation to estimated bottomhole pressure, and then Turner's critical velocity should be compared to the calculated velocity at bottomhole conditions.

Indicates that Turner's method is conservative when using the Ros correlation and the IPR intersection, because it indicates a higher rate than necessary to maintain continuous liquid unloading than determined from inspection of the last possible "J" curve-IPR curve intersection.

The author outlines a methodology for intermitters, siphon strings, plunger applications, foaming agents, compression, gas lift and pumping methods.

Asheim, H., "MONA, an Accurate Two-Phase Well Flow Model Based on Phase Slippage," **SPE No. 12989**, Presented at the 1984 SPE European Petroleum Conference, October 25 - 28, London, UK.

The author has developed a computer model (slanted hole) for two phase pressure drop. Field data is available for the Forties Field, Ekofisk Field and Prudhoe Bay flowlines.

Peffer, J., Miller, M, and Hill, A., "An Improved Method for Calculating Bottomhole Pressures in Flowing Gas Wells with Liquid Present," **SPE No. 15655**, Presented at the 61St Annual Technical Conference and Exhibition, October 5-8, 1986, New Orleans, LA.

The authors have modified the Cullender and Smith method to include the contribution of entrained liquid to gravitational gradients.

Determined that an absolute roughness of approximately 0.0018 inches improved the pressure drop correlations, as compared to Cullender and Smith's value of 0.0006 inches, which was for new pipe, improved the pressure drop correlations, as compared to Cullender and Smith's value of 0.0006 in which was for new pipe.

Data tables are available (condensate) from Govier and Fogarasi's paper and 50 Texas Railroad Commission Wells.

Upchurch, E., "Expanding the Range fro Predicting Critical Flowrates of Gas Wells Producing from Normal Pressured Water Drive Reservoirs," **SPE No. 16906**, Presented at the 62 Annual Technical Conference and Exhibition, September 27-30, 1987, Dallas, TX.

This model is for determining critical rates in wells producing more than 150 bbl/MMcf, which is probably not relevant for stripper oil and gas wells.

Oden, R., and Jennings, J., "Modification of the Cullender and Smith Equation for More Accurate Bottomhole Pressure Calculations in Gas Wells," **SPE No. 17306**, Presented at the SPE Permian Basin Oil and Gas Recovery Conference, March 10-11, 1988, Midland, TX.

The authors modify the Cullender and Smith equation by adding as gas¬water ration tem and a friction factor term as given by the explicit Jain Swamee correlation.

Improvement was shown that using an apparent roughness of 0.0023 inches instead of an absolute roughness of 0.0006 inches further reduced error in the computation of flowing bottomhole pressures.

The technique is for smooth-turbulent and rough-turbulent flow of water and gas in the wellbore.

Data is compiled from SPE No. 15655.

Rendeiro, C., and Kelso, C., "An Investigation to Improve the Accuracy of Calculating Bottomhole Pressures in Flowing Gas Wells Producing Liquids," **SPE No. 17307**, Presented at the SPE Permian Basin Oil and Gas Recovery Conference, March 10-11, 1988, Midland, TX.

This technique is a refinement of the average temperature and pressure method through the use of an adjustment in gas gravity to account for the presence of well stream liquids.

The authors used data from SPE No. 15655.

Chuandong, Y., "Design Study for Optimization of Tubing String Producing Gas with Water from Wells," **SPE No. 17850**, Presented at the SPE International Meeting on Petroleum Engineering, November 1-4, 1988, Tianjin, Peoples Republic of China.

Flow at the tubing shoe is reviewed to determine critical rates.

Neves, T., and Brimhall, R., "Elimination of Liquid Loading in Low-Productivity Gas Wells," **SPE No. 18833**, Presented at the SPE Production Operations Symposium, March 13-14, 1989, Oklahoma City, OK.

This paper discusses factors affecting methods to alleviate liquid loading problems and guidelines for selecting, in advance, the optimum method to be used when liquid loading occurs.

The authors constructed a computer program to 1) calculate the existing gas velocity profile and the critical gas velocity profile as a function of depth, 2) predict the flowing bottomhole pressure, and 3) study the effects of various parameters on long-term gas production.

Used the Beggs and Brill multiphase pressure drop correlation was used to determine the pressure at various positions in the wellstring. The Turner equation was used to calculate the critical velocity profile.

Alternate flow/shut-in periods, swabbing, smaller diameter production tubing, foaming agents, plunger lift, sucker rod pumping and gas lift techniques were reviewed.

No rationale for selecting optimum lift methods was apparent. However, the authors suggest producing the well using its own energy as long as possible, using smaller tubing, foaming agents, and plunger lift, then revert to rod pumping or gas lift.

Oudeman, P., "Improved Prediction of Wet-Gas-Well Performance," **SPE No. 19103,** SPE Production Engineering, August 1990, pp. 212-216.
There is a discussion of published liquid loading predictive models (Turner, Gray tubing performance) and their drawbacks.

The Turner method **DOES NOT** predict a well's minimum flow rate.

There is a critical pressure drawdown below which fluid does not enter the wellbore.

Coleman, S., Clay, H., McCurdy, D., and Norris, H. "A New Look at Predicting Gas-Well Load-Up," **SPE No. 20280**, Journal of Petroleum Technology, March 1991, pp. 329-333.

The test wells have WHFPs less than 500 psi, where Turner's were greater than 500 psi.

The amount of condensed water increases with a decline in reservoir pressure.

The authors were able to match their data without the 20% upward adjustment Turner enforced.

In most cases, wellhead conditions controlled the onset of liquid load-up.

The liquid/gas ratios for the data ranged from 1 to 22.5 MMscf and had no influence on the determination of liquid load-up.

The primary source of water was condensed water.

Slugging water production will not follow the liquid droplet methodology because a differing transport mechanism is occurring.

In most cases, wellbore conditions can be used to determine the onset of liquid loading. However, for concentric tubing strings where the tubing/packer is a significant distance from the completion interval, flowing conditions of the largest diameter segment should be used to predict the wellbore critical rate.

Coleman, S., Clay, H., McCurdy, D., and Norris, H. "Understanding Gas-Well Load-Up Behavior," **SPE No. 20281**, Journal of Petroleum Technology, March 1991, pp. 334-338.

The time for a well to load-up and die is inversely proportional to the rate of liquid influx into the wellbore.

Coleman, S., Clay, H., McCurdy, D., and Norris, H. "The Blowdown-Limit Model," **SPE No. 20282**, Journal of Petroleum Technology, March 1991, pp. 339-343.

To blow down a well successfully, three criteria must be met.

1. Differential wellbore pressures must be capable of inducing reservoir flow.

2. A bottomhole superficial gas velocity of 5 to 10 ft/sec is required to initiate slug removal.

3. For a well to have a successful blowdown, it must be capable of delivering gas above its critical rate fro a minimum of 3 hours.

Coleman, S., Clay, H., McCurdy, D., and Norris, H. "Applying Gas-Well Load-Up Technology," **SPE No. 20283**, Journal of Petroleum Technology, March 1991, pp. 344-349.

A table of alternate depletion methods is included.

Typical post-critical rate deliverability is about 43% of a well's potential deliverability.

Henderson, F., "Producing the Oriskany in Southwestern Pennsylvania," **SPE No. 23430**, Presented at the 1991 SPE Eastern Regional Meeting, October 22¬25, 1991, Lexington, KY.

Remedial acts have including well blowing, with and without surfactant and plunger lift installation on six wells. Two wells were receptive to the plunger lift technique.

Adams, L., and Marsili, D., "Design and Installation of a 20,500-ft Coiled Tubing Velocity String in the Gomez Field, Pecos County, Texas," **SPE No. 24792**, Presented at the 67th Annual Technical Conference and Exhibition, October 4-7,

1991, Washington, DC.

Two coiled tubing velocity string applications (1-1/2 inch) were performed in the Delaware Basin prior to this installation.

Installation of 1-1/4 inch coiled tubing (20,500') was selected as the optimum configuration.

Coil was run with a live well.

Martinez, J., and Martinez, A., "Modeling Coiled Tubing Velocity Strings," **SPE No. 30197**, Presented at the Petroleum Computer Conference, June 11-14, 1995, Houston, TX.

A coiled tubing velocity of 7 to 12 ft/sec in the lower third of the tubing is best.

The authors recommend the use of the Beggs/Brill correlation for flow and the Lasater correlation for solution gas.

A Liquid hold-up of 0.2 or less and the achievement of the lowest pressure at the perforations while maximizing rate are ideal considerations.

Elmer, W., "Tubing Flowrate Controller: Maximize Gas Well Production from Start to Finish," **SPE No. 30680**, Presented at the 71St Annual Technical Conference and Exhibition, October 22-25, 1995, Houston, TX.

A table of critical flowrates is presented based on tubing size (3/4 to 2-3/8 inch) and tubing pressure (50 to 500 psia).

Cox, S., "Gas Well Optimization: Using Velocity as the Key Component in Choosing Tubing Size," **SPE No. 35579**, Presented at the SPE Gas Technology Conference, April 28-May 1, 1996, Calgary, Alberta, Canada.

The author uses nodal analysis (tubing performance and inflow curves) to optimize tubular selection based on velocity.

Low pressure, low productivity wells may perform better with smaller tubing due to the smaller cross-sectional area. A siphon string, run inside the existing tubing, may be a superior alternative, allowing internal or annular flow to exist.

When tubing is found to be too large, down hole chokes should be considered as an alternative to running smaller tubing.

Ouyang, L., and Aziz, K., "Development of New Wall Friction Factor and Interfacial Friction Factor Correlations for Gas-Liquid Stratified Flow in Wells and Pipelines," **SPE No. 35679**, Presented at the SPE Western Regional Meeting, May 22-24, 1996, Anchorage, AK.

Developed friction factors to predict liquid holdup values, based on Minami and Beggs test values.

Gunawan, R., and Dyer, G., "Tubing Size Optimization in Gas Depletion Drive Reservoirs," **SPE No. 37001**, Presented at the SPE Asia Pacific Oil and Gas Conference, October 28-31, 1996, Adelaide, Australia.

The authors use nodal analysis and gas load-up technology to identify optimum tubing size.

Tubing size was increased from 2-3/8 to 3-1/2 inch in seven wells, yielding a 50 MMcfd increase in productivity.

Field results show that the Gray correlation (Tubing Performance) underpredicts the actual FBHP in wells with low WHFP.

High-permeability (2,000 and-ft) reservoir abandonment pressure is not affected by tubing size. Otherwise, tubing size is important.

Azouz, I., Shah, S., Vinod, P., and Lord, D., "Experimental Investigation of Frictional Pressure Losses in Coiled Tubing," **SPE No. 37328**, Presented at the SPE Eastern Regional Meeting, October 23-25, 1996, Columbus, OH.

This paper presents an experimental investigation of tubular frictional pressure loss in coiled tubing and straight sections of seamed and seamless tubing.

Fluids investigated include water, linear guar gum and hydroxypropyl guar (HPG), and borate-crosslinked guar gum and HPG.

Results obtained with water indicate tubing curvature as well as the seam impact frictional pressure drop while non-Newtonian fluids are impacted by curvature only.

In straight sections of tubing, seamless tubing had a higher friction factor, due to innate roughness, as compared to the seamed tubing, which was much closer to true smooth pipe. The authors conclude that the seam alters the turbulence spectrum by damping the high turbulence frequencies. This causes a decrease in the pressure drop.

$f(\text{seamed}) = 1.667*(Nre^{-0.049})*f(\text{seamless})$……for water

Nosseir, M., Darwich, T., Sayyouh, M., and Sallaly, M., "A New Approach for Accurate Prediction fo Loading in Gas Wells Under Different Flowing Conditions," **SPE No. 37408**, Presented at the SPE Production Operations Symposium, March 9-11, 1997, Oklahoma City, OK.

> Developed critical velocity correlations for the transition (1 < Nre < 1000) and highly turbulent ($2*10^5$ < Nre < 10^6) flow regimes, while Turner's original (non-adjusted equation) was valid for 10^4 < Nre < $2*10^5$.
>
> Has a graphical representation of drag force and three data tables re-studying Turner's and Exxon's Data.

Farshad, F., and Garber, J., "Relative Roughness Chart for Internally Coated Pipes (OCTG)," **SPE No. 56587**, Presented at the 75th Annual Technical Conference and Exhibition, October 3-6, 1999, Houston, TX.

> The relative roughness of internally coated pipes (phenolic, epoxy and modified phenolic-epoxy) are given based on two roughness measurement devices. In addition, the average roughness value from the two measurements is given versus diameter for coated and commercial steel.
>
> Best-fit equations (though unreadable at this time) are presented.

Scott, W., and Hoffman, C., "An Update on Use of Coiled Tubing for Completion and Recompletion Strings," **SPE No. 57447**, Presented at the SPE Eastern Regional Meeting, October 21-22, 1999, Charleston, WV.

> An estimated 15,000 wells have coiled tubing installed in them as velocity or siphon strings.

Medjani, B., and Shah, S., "A New Approach for Predicting Frictional Pressure Losses of Non-Newtonian Fluids in Coiled Tubing," **SPE No. 60319**, Presented at the 2000 SPE Rocky Mountain Regional/ Low Permeability Reservoirs Symposium, March 12-15, 2000, Denver, CO.

> Fanning Friction (f) = 0.0079 / Nre^0.25
> For Newtonian fluids in straight pipe (Blasius Formula)

Li, M., Sun, L., and Li, S., "New View on Continuous-removal Liquids from Gas Wells," **SPE No. 70016**, Presented at the SPE Permian Basin Oil and Gas Recovery Conference, May 15-16, 2001, Midland, TX.

> Liquid droplets are deduced to be flat instead of round, resulting in a drag coefficient value of 1.

Equations are in metric.

Farshad, F., Rieke, H., and Mauldin, C., "Flow Test Validation of Direct Measurement Methods Used to Determine Surface Roughness in Pipes (OCTG)," **SPE No. 76768**, Presented at the SPE Western Regional Meeting, May 20-22, 2002, Anchorage, AK.

There is a very beneficial advantage in the use of internally plastic coated pipes for improving the flow performance by lowering wall surface roughness and friction factor values.

Moody friction is 4 times fanning friction.

The John Gandy Corporation of Conroe, Texas supplied the oil field country tubular goods.

All data showed that Rzd (mean peak to valley height) derived friction factor gave the best correlation with the flow test results.

Technical Progress Report
Final Report
May 15, 2002 to January 31, 2004
Subcontract No. 2280-SI-SOE-1025

Injectivity Improvement of Low Permeability Reservoirs
Big Sinking Field, Lee County, Kentucky

February 2004

DISCLAIMER

Table of Contents

Executive Summary

The injectivity improvement study in the Big Sinking Field, Lee County, Kentucky demonstrated that a low interfacial tension solution can be used to alter the relative permeability characteristics near an injection well and increase water injection rates. A laboratory program consisting of interfacial tension, phase behavior, and linear and radial corefloods designed alkaline-surfactant polymer solutions demonstrating potential to increase injectivity. A core was taken for the laboratory program and to provide a new well bore for the field trial. Injection of a sodium hydroxide (alkali) plus ORS-164HF (surfactant) solution increased water injectivity by 220%. A paper will be presented at the SPE/DOE Fourteenth Symposium in April 2004 to continue technology transfer.

Results and Discussion

A. **Objectives of Project**
To demonstrate that a low interfacial tension alkaline-surfactant solution can increase injectivity in the Big Sinking Field using laboratory and field evaluations.

B. **Laboratory Evaluations**

1. **Fluid Analysis**
Oil and water samples received were analyzed. The oil is a 39 API gravity oil with a dead oil viscosity of 7.3 cp at 68°F. Produced and fresh water analyses are listed in the following table. Zacharia Lake water will be used to dissolve chemicals in the laboratory study. Chemical dissolution water was switched to City Water for the field injectivity. As a result, softening was required and initial injection of alkali and surfactant reduced injectivity due to alkaline precipitates. Injectivity was restored with acid.

Ion	Townsend # 5 Produced Water	Zacharia Lake Water	City Water
	Ion Concentration mg/L		
Calcium	2,250	4	65
Magnesium	480	2	35
Barium	25	<5	---
Strontium	160	<5	---
Sodium	8,300	14	---
Potassium	60	<5	---
Iron	10	<5	---
Chloride	18,257	12	---
Sulfate	3	7	---
Carbonate	0	0	---
Bicarbonate	187	30	---
Total Dissolved Solids	33,573	52	540
pH	7.13	7.43	---

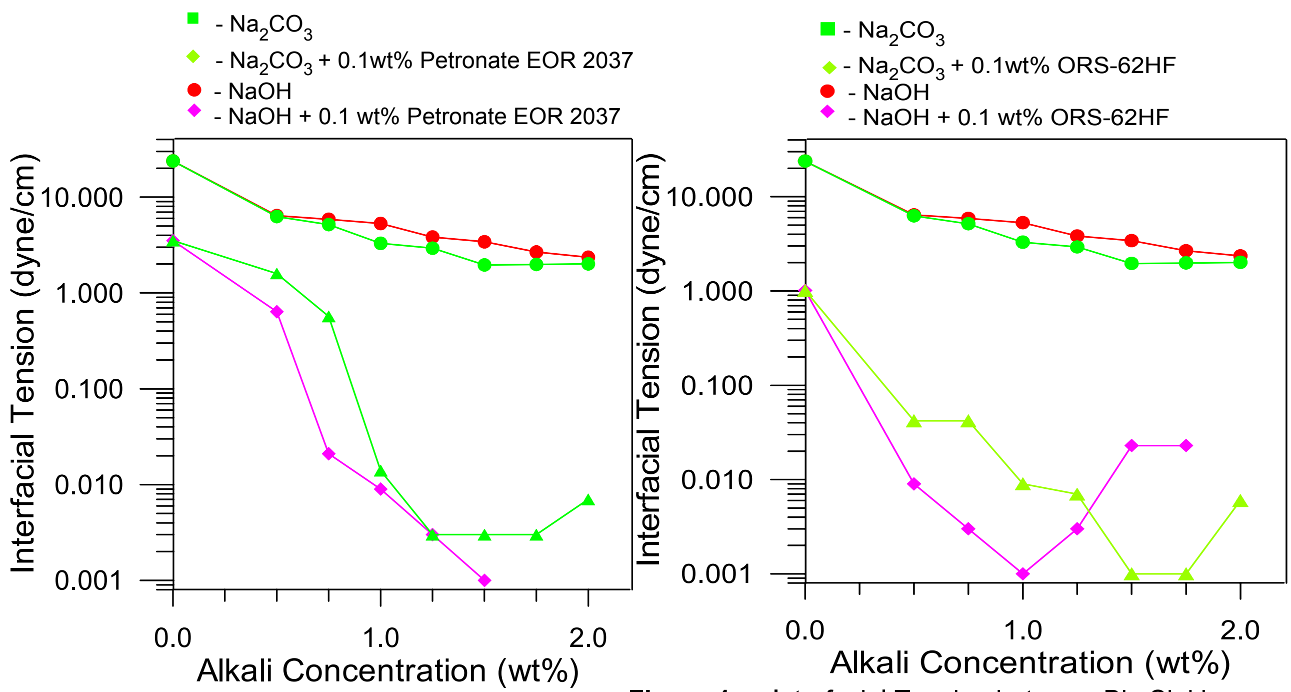


Figure 1 Interfacial Tension between Big Sinking Crude Oil and Aqueous Alkali and Alkali Surfactant

2. **Interfacial Tension and Phase Behavior Screening**
   Interfacial tension and phase behavior screening were performed by blending two alkaline agents (sodium carbonate, Na_2CO_3 and sodium hydroxide, NaOH) with twenty two surfactants. Seven alkali concentration ranging from 0.5 to 2.0 wt% were tested with 0.1 wt% active surfactant. An additional twelve surfactants were tested with only three alkali concentrations.

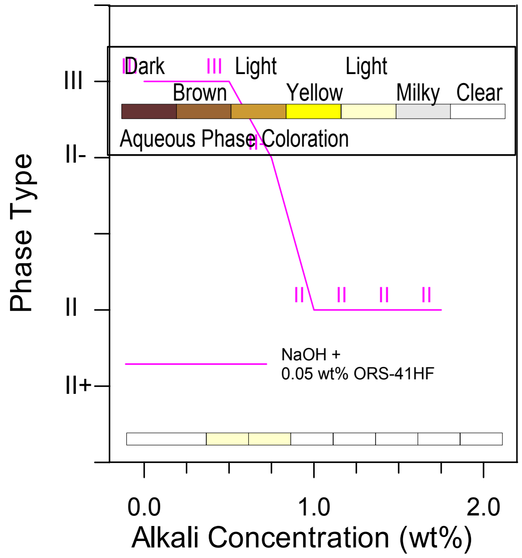


Figure 2 Phase Behavior of Alkaline plus Surfactant Solution with Big Sinking Crude Oil

Interfacial tension values were reduced to 0.001 dyne/cm with eleven of the surfactants tested with either NaOH or Na_2CO_3. Interfacial tension values of 0.001 dyne/cm represent an interfacial tension reduction of 23,680 fold and, therefore, a capillary number increase of 23,680. Eighteen of the surfactants reduced the interfacial tension by at least 5,000 fold when blended with alkali. Based on capillary number theory, sufficient interfacial tension reduction was achieved to expect a reduction of the oil saturation and to change the effective water permeability of the Big Sinking rock.

Two surfactants (ORS 62 HF and Petronate EOR 2037) interfacial tension versus alkali concentration curves are shown in Figure 1. Type III and type II- phase types were observed with the majority of alkali and surfactant solutions with low interfacial tension values, type III and type II- being considered optimum for oil saturation reduction. Phase behavior change with ORS-41HF and NaOH is shown in the Figure 2. Phase type nomenclature is designated according to Nelson and Pope.[1]

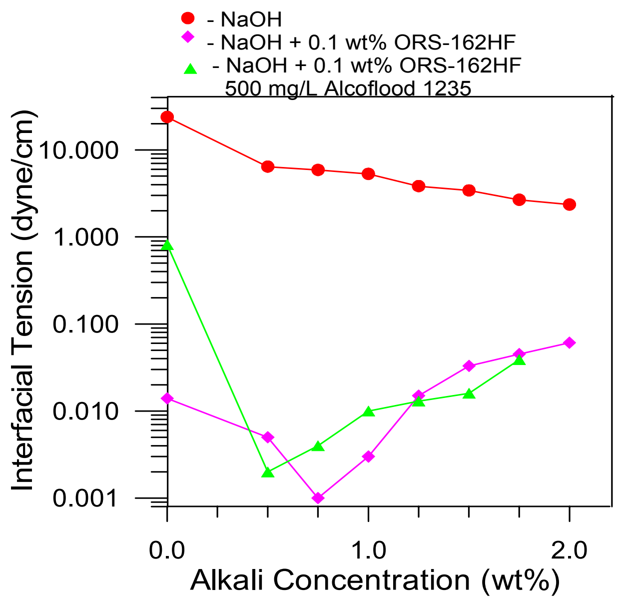


Figure 3 Effect of Polyacrylamide Polymer on the Interfacial Tension between Big Sinking Crude Oil and Aqueous Alkali plus Surfactant

3. Effect of Polyacrylamide Polymer on Solution Characteristics

Polyacrylamide polymer was added to alkaline-surfactant solutions with low interfacial tension values and favorable phase behavior, and the interfacial tension and phase behavior was measured. Addition of polymer to the solution resulted in a minimal change of interfacial tension and phase behavior characteristics of most alkaline-surfactant solutions. The effect of polymer on a NaOH plus ORS-162HF solution is shown in Figure 3.

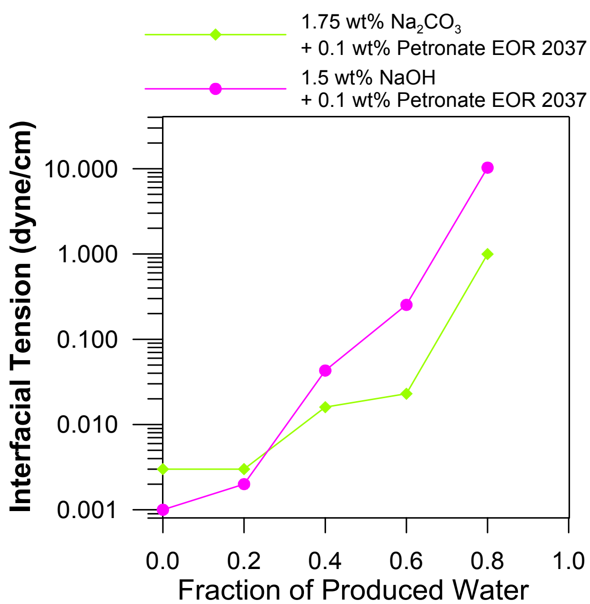


Figure 4 Effect of Produced Water Dilution on the Interfacial Tension Between Big Sinking Crude Oil and Aqueous Alkali plus Surfactant

4. Produced Water Dilution Effect on Solution Characteristics

To help determine which solution's low interfacial tension and phase behavior characteristics will persist when injected into the Big Sinking reservoir, the alkaline-surfactant solutions were diluted with produced water and the interfacial tension and phase behavior measured. Alkaline-surfactant solutions were diluted with 20, 40, 60, and 80% produced water. Low interfacial tension values were generally better maintained with Na_2CO_3 as opposed to NaOH. Interfacial tension values remained lower at greater dilution with higher alkali concentration. A typical interfacial tension curve with produced water dilution is shown in Figure 4.

5. Injectivity Improvement Linear Corefloods

a. **Relative Permeability Characteristics** - Figure 5 shows the relative permeability using produced water as the displacing phase. Big sinking core displayed water-wet characteristics. Mobility ratio for water displacing oil is favorable, averaging 0.6. Initial oil saturation averaged 0.69 Vp. Produced water injection reduced the average oil saturation to 0.41 Vp, recovering 41% OOIP.

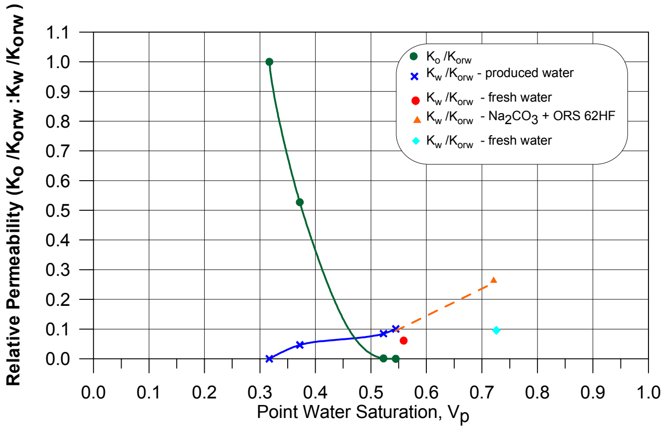


Figure 5 Big Sinking Water-Oil Relative Permeability, Dark Green is Effective Permeability to Produced Water, Blue is Effective Permeability to Oil, Red Dot is Effective Permeability to Fresh Water before Alkali plus Surfactant, Orange Dashed Line and Triangle is the Effective Permeability to Alkali plus Surfactant, Powder Blue Dot is Effective Permeability to Water after Alkali plus Surfactant

When fresh water was injected after the produced water, the relative permeability characteristics changed. Average effective permeability to water at residual oil decreased to 2.6 md from 4.0 md. As a result, mobility ratio becomes more favorable at 0.4. However, the decline in effective water permeability means that water injectivity decreased by 35%. Fresh water injection produced an additional 0.01 Vp of oil bringing the total oil recovery to 42% OOIP.

b. **Alkaline-Surfactant Injectivity Improvement** - Two alkaline-surfactant solutions were injected into two Big Sinking linear cores from the Second Sand followed by fresh water to reduce the residual oil saturation and increase the effective permeability to water. The data are summarized in Table 1. Figure 5 depicts the changes in effective water permeability for a fresh water and a 1.5% Na_2CO_3 + 0.1% ORS-62HF solution. Effective water permeability decreases when fresh water is injected, red dot, indicating a sensitivity of the Second Sand to lower total dissolved solids water. When the alkaline plus surfactant solution, the effective water permeability increases to double the effective water permeability to fresh water, orange triangle and dashed line in Figure 5. Subsequent fresh water injection results in a decreased the effective permeability to water for the Na_2CO_3 coreflood but not the NaOH coreflood, see Table 1.

Table 1
Oil Saturation, Effective Water Permeability and Percent Effective Water Permeability Change Summary, Big Sinking Linear Corefloods

Injected Solutions	Oil Saturation Vp	Effective Water Permeability md	percent increase over fresh wtr
Flood 1			
produced water	0.45	3.7	-----
fresh water	0.44	2.7	-----
1.5% Na_2CO_3 + 0.1% ORS-62HF*	0.28	11.5	425%
fresh water flush	0.27	4.2	155%
Flood 2			
produced water	0.38	4.3	----
fresh water	0.37	2.5	----
0.75% NaOH + 0.2% AX-210-6*	0.33	7.8	310%
fresh water flush	0.30	8.1	325%

* Surfactant concentrations are active concentrations

Injectivity was improved with both alkaline-surfactant solutions an average of 370%. Injectivity improvement was maintained with subsequent fresh water injection at an average 240%. The hydroxide solution maintained the injectivity improvement perhaps due to the higher pH reacting with the clays as described by Sydansk for KOH solutions.[2]

c. **Polymer Addition to Alkaline-Surfactant Solutions** - Because inclusion of polymer into the alkaline-surfactant solution results in a significant decrease in oil saturation, two manufacturer's polymers were added to the alkaline-surfactant solutions and injected into the Big Sinking core. Both Ciba Speciality Chemicals' Alcoflood 1235 and SNF Floerger's Flopaam 3230 injected into and flowed through the Big Sinking core. The oil saturation change and effective water permeability changes are listed in Table 2.

Table 2
Effect of Polymer on Effective Permeability Changes in Big Sinking Core
After Injection of Alkali plus Surfactant

Injected Solutions	Oil Saturation Vp	Effective Water Permeability md	percent increase over initial
Flood 1			
fresh water	0.44	2.7	----
1.5% Na_2CO_3 + 0.1% ORS-62HF	0.28	11.5	425%
fresh water flush	0.27	4.2	155%
1.5% Na_2CO_3 + 0.1% ORS-62HF + 950 mg/L Flopaam 3230S	0.17	—	----
fresh water flush	0.17	3.3	120%
produced water flush	0.17	5.2	190%
Flood 2			
fresh water	0.37	2.5	----
0.75% NaOH + 0.2% AX-210-6	0.33	7.8	310%
fresh water flush	0.30	8.1	325%
0.75% NaOH + 0.2% AX-210-6 + 950 mg/L Alcoflood 1235	0.16	----	----
fresh water flush	0.13	6.0	180%
produced water flush	0.13	10.9	435%

* Surfactant concentrations are active concentrations

Both polymers reduced the effective permeability to water as expected. However, the injectivity to water was still greater than it was before the core was treated with the alkaline-surfactant solutions. In both cores, about 75% of the effective permeability to water was maintained suggesting little difference between the permeability reduction characteristics of the two polymers. Injection of produced water after the fresh water flush increased injectivity in both cores, suggesting the effective permeability loss is reversible.

Injection of additional polymer concentrations to calculate amount required to give an alkaline-surfactant-polymer solution a mobility ratio of one or less indicates that the concentration is dictated by the adsorption of polymer onto the rock. A concentration of 550 mg/L is necessary to give the displacing solution a unit mobility ratio.

Total oil recovery after all injection averaged 0.59 Vp or 86% OOIP. Final oil saturation averaged 0.10 Vp. This suggests that injection of an alkaline-surfactant-polymer solution into the Big Sinking reservoir has the potential to produce incremental oil in addition to injectivity improvement.

6. **Injectivity Radial Coreflood**

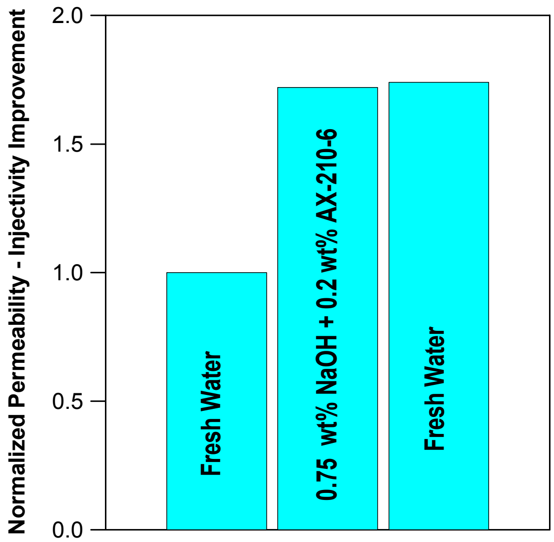


Figure 6 Normalized Effective Fresh Water Permeability Improvement by Alkali plus Surfactant Injection, Effective Water Permeability is Normalized to the End of the Waterflood

Vertical wells flow characteristics are better represented with radial corefloods than with linear corefloods. A radial injectivity improvement coreflood was performed to simulate the increase in injectivity potential Fresh water was injected, 7 Vp, to residual oil saturation followed by 4.1 Vp of 0.75 wt% NaOH plus 0.2 wt% AX-210-6. Fresh water, 4.3 Vp, was subsequently injected and ultimately produced water to determine injectivity changes. The injectivity change is shown in the adjacent figure. Injectivity improved 173% during alkaline-surfactant injection as well as for the following fresh water injection. Produced water injectivity was an improved by 285%. This compares with a linear coreflood injectivity improvement of 310% and 325% with the same alkaline-surfactant solution and fresh water flush.

Mobility ratio for water displacing crude oil was 1.1. During alkali-surfactant and fresh water injection, the mobility ratio for injected phase displacement of oil was 1.9 and during the final produced water injection the mobility ratio increased to 3.1. Mobility ratio change is a result of an increase of effective water permeability. Oil saturation decreased from an initial oil saturation of 0.729 Vp with fresh injection to 0.314 Vp. The final oil saturation was 0.220 Vp after chemical injection and fresh water flush. Total oil recovery was 69.8% OOIP. Therefore, injection of an alkaline-surfactant solution has changed the relative permeability characteristics of the Big Sinking core.

7. **Alkaline-Surfactant-Polymer Radial Corefloods**

Five radial corefloods were performed to determine the effect on injectivity of polymer addition to the alkaline-surfactant solution and to determine the oil recovery potential of an alkaline-surfactant-polymer injection sequence. The coreflood sequence was to inject approximately 3.3 Vp fresh water followed by 0.3 Vp alkaline-surfactant-polymer followed by 0.3 Vp polymer solution and ultimately fresh water, 3.4 Vp, to flush chemicals from the core for mass balance. Oil recovery, final oil saturation, peak oil cut due to chemical injection, and change in effective water permeability are listed in Table 3.

Table 3
Radial Coreflood Oil Recovery and Injectivity Change

Injected Solutions	Oil Recovery % OOIP Waterflood	Oil Recovery % OOIP ASP flood	Peak Oil Cut %	Final Oil Saturation Vp	Change of Effective Water Permeability** %
0.75% NaOH + 0.2% AX-210-6 + 550 mg/L 3230S*	50.0	12.1	21.4	0.264	-26.2%
1.5% Na_2CO_3 + 0.1% EOR 2037 + 550 mg/L 3230S*	54.8	7.1	4.9	0.232	-30.4%
1.25% Na_2CO_3 + 0.1% AX 131-3 + 550 mg/L 3230S*	53.7	15.1	16.7	0.218	no data
1.5% Na_2CO_3 + 0.1% ORS-62HF + 550 mg/L 3230S*	55.0	6.1	6.7	0.247	-94.5%
0.5% NaOH + 0.1% ORS-162HF + 550 mg/L 3230S*	56.4	9.1	13.2	0.209	+21.7%

* Surfactant concentrations are active concentrations, 3230S is Flopaam 3230S
** fresh water after chemical relative to fresh water before chemical

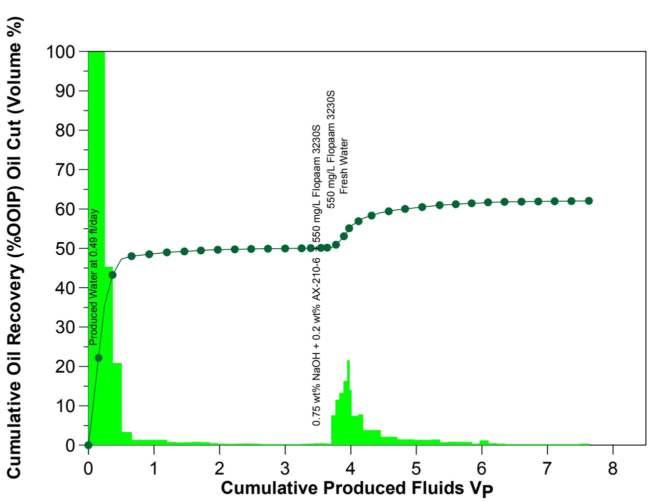


Figure 7 Waterflood and Chemical Flood Oil Recovery, dotted dark green line is cumulative oil recovery, lime green histogram is oil cut, chemical flood begins at approximately 3.5 Vp.

Average initial oil saturation was 0.688 Vp and average waterflood residual oil saturation was 0.316 Vp. Average waterflood oil recovery was 54.0% OOIP or 0.371 Vp. Average chemical flood oil recovery was 12.0% OOIP or 8.2 Vp. Figure 7 shows the oil cut and oil recovery performance for the NaOH plus AX-210-6 plus 550 mg/L Flopaam 3230S radial coreflood.

Mobility ratio average for water displacing oil was 0.6. The mobility ratio during chemical injection averaged 0.2 so chemical flood mobility was sufficient at the injected polymer concentration.

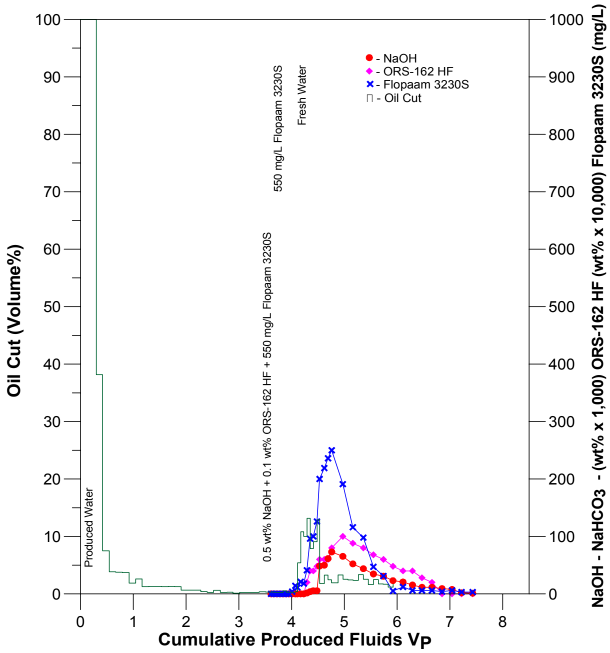


Figure 8 Produced Chemical Concentration and Oil Cut as a Function of Cumulative Total Fluids Produced

Good mobility control was also reflected in the position of the produced chemicals relative to the oil bank. Figure 8 for NaOH plus ORS-162HF plus 550 mg/L Flopaam 3230S shows the chemical banks behind the oil bank.

Chemical retention by the Big Sinking rock is low. Sodium hydroxide average retention was 354 lb/acre-ft and sodium carbonate average retention was 1,484 lb/acre-ft. Surfactant average retention was 134 lb/acre-ft and that of polymer was 77 lb/acre-ft.

Injectivity to fresh water after injection of the alkaline-surfactant-polymer and polymer solutions generally declined as shown in Table 3. Sodium hydroxide systems did not lose as much injectivity as did sodium carbonate systems. Linear corefloods demonstrated the same conclusion. Figure 9 shows that with a NaOH plus ORS -162HF system, injectivity actually improved despite the permeability reduction of the polyacrylamide polymer.

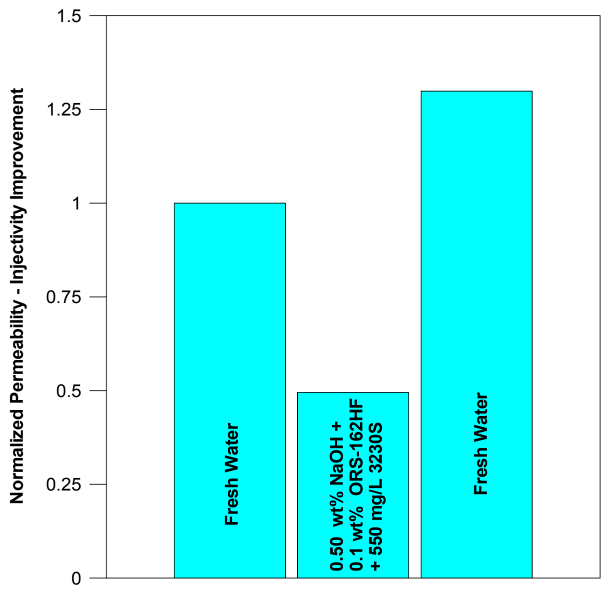


Figure 9 Injectivity Improvement as Normalized Effective Water Permeability, for Injection of NaOH-ORS-162HF-Flopaam 3230S in a Radial Coreflood

C. Field Evaluations

1. Core of Well and Well Location

The test well, #1T E.L. Rogers, was air drilled to a total depth of 1,217 feet. An 8 ¾ inch hole was drilled to 1,120 feet (just above the zone to be cored) and 7 inch casing was run and cemented to surface. The Corniferous formation was cored with a total of 60 feet of 4 inch core from 1130 to 1190 feet being recovered. The well was open hole logged showing a net of 25 feet of continuous net pay in the primary waterflood zone and 11 feet from a lower, tighter zone.

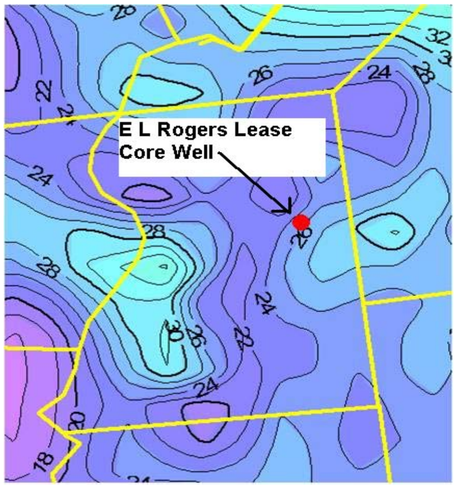


Figure 10 Single Well Injectivity Test Well Location and Net Pay Isopach

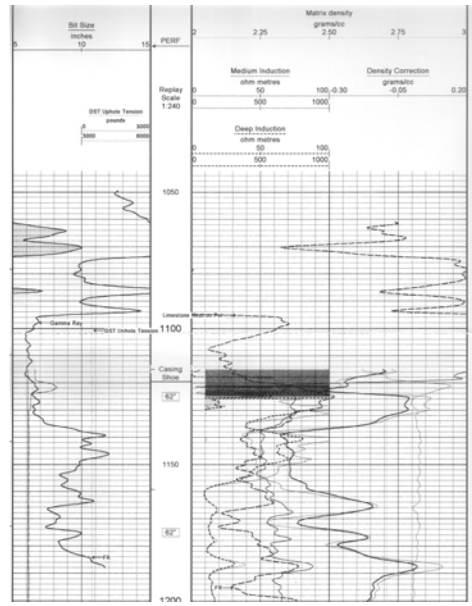


Figure 11 Log of #1T E.L. Rogers Well

The resistivity is high on the log due to the injection of fresh water. The log is shown in Figure 11.

2. **Injectivity Test**

The injectivity test was performed by injecting fluid into the #1T E.L. Rogers well. Water was initially be injected followed by alkaline-surfactant solution followed by water. The initial alkaline-surfactant solution selected from the linear corefloods, 0.75 wt.% NaOH plus 0.2 wt.% AX-210-6, had to be replaced with a 0.50 wt.% NaOH plus 0.1 wt.% ORS-162HF solution because of the manufacturers inability to supply the AX-210-6. Radial coreflood injectivity improvement with the NaOH plus ORS-162HF plus polymer solution is shown in Figure 9.

a. **Well Set Up** - The cored well was completed for the injectivity test open hole. First the well was plugged back to 1162 feet (354 m), just below the primary zone. Second, the well was bailed clean with a service rig and bail tested at 30 barrels per day. Third, two inch, internally lined tubing and a packer were run to 1100 feet.

b. **Surface Equipment** - The pumping and mixing equipment were designed to use liquid NaOH delivered in 55 gallon drums at 50 wt %. Surfactant was also delivered in 55 gallon drums at 50% active. The primary mixing constraint was to blend the NaOH with water prior to adding the surfactant. The pH prior to adding the surfactant was approximately 13.2. The resultant solution was filtered to 5 microns. All piping downstream of added NaOH was stainless steel including the injection pump. The pump was setup as a mixer for NaOH with part of the pumped volume being recycled. The surfactant was mixed into the injection solution downstream of the pump. Two chemical injection pumps were setup to be able to blend 0.5 wt% NaOH plus 0.1 wt% active ORS-162HF. At the required concentrations of chemicals, the injection pump volumes were

27.4 gallons of NaOH (50 wt%) and 8.0 gallons of surfactant (50% active) per 100 barrels of fresh water. The maximum wellhead pressure was set at 800 psig.

c. **Injectivity Test Program** - The injectivity test was to be completed in four months. The injected sodium hydroxide/ORS-162HF solution was preceded with a pre-flush of 1,500 barrels of fresh water. During the pre-flush, a base injection rate and injection pressure was established. Next, 1,500 barrels of an alkaline-surfactant solution was injected to treat approximately a 25 foot radius around the wellbore. Fresh water is then injected to establish the injection rate and injection pressure followed by the injection of produced water.

d. **Injection History** - Injection of fresh water started on September 5, 2003. The initial injection rate was 90 BWPD. After one month and 2,600 barrel of continued water injection, the rate stabilized at 41 BWPD and 910 psig bottom hole pressure. The alkaline-surfactant solution injection began at the 41 BWPD; however, after injecting for one day the well pressured up to the maximum bottom hole pressure of 1,180 psi and the rate dropped below 20 BWPD. The well was shut in. A ¾ inch circulating string was run in and circulated the well clean. Samples of the bottoms up material along with the surfactant, source water, and filter element were sent to lab for analysis. It was discovered that while water the divalent cation concentration of the water used in the laboratory for chemical dissolution were low enough to dissolve alkali, the city water used in the injectivity test required softening. A loss of injectivity resulted due to precipitation and skin damage. The injection rate decline was compounded by mixing too high a concentration of chemicals due to mechanical difficulties. An attempt to restart water injection was made but the skin damage was too great. Two hundred gallons (5 bbl) of 15% HCl was spotted on bottom of the well. Injectivity was restored by dissolving the hardness precipitate causing the skin damage. The initial injection pump had to be changed out due to the packing not being resistant to a high pH fluid. A 500 barrel buffer of fresh water was injected. Alkali plus surfactant dissolved in softened city water injection resumed on November 21, 2003. The equipment was initially designed to run in warmer weather. Because the 50 wt.% NaOH solution solidifies at 40°F, the equipment had to be weatherized. NaOH was stored in a warm building and brought out as needed. The 1,500 barrel treatment of alkaline-surfactant solution was completed on December 25, 2003. A nine day injection of fresh water followed. Stabilized fresh water injection rate was 75 BWPD at 760 psig an increase of over 30 BWPD at lower injection pressure.

If injectivity change ratio is defined as

$$Injectivity\ Change = \frac{\left[q / \Delta P\right]_{final}}{\left[q / \Delta P\right]_{initial}}$$

where q is injection rate, ΔP is the bottom hole injection pressure, final is water injection after chemical, and initial is water injection before chemical, the injection improvement due to injecting the alkaline-surfactant solution is 2.19. This represents a 220% increase in injection rate, about two thirds the order of magnitude observed in the linear corefloods and greater than that observed with the NaOH plus ORS-162HF-polymer radial coreflood.

D. **Economics of Alkaline/Surfactant Treatment**

The basic ingredients of the treatment are alkali and surfactant. The delivered cost for the NaOH was US$1,725, including US$500 deposit on the drums. The designed surfactant was US$1,250 delivered on site from Houston, TX. Design costs are dependent upon the economies of scale. Fresh water used will be dependent upon hardness and availability in the area. Pumping and blending equipment is dependent upon the degree of automation. In this case, the field treatment cost estimate is US$8,500. For a mature waterflood with an efficiency of 15:1 (barrel injected/barrel oil produced), a 30 barrel increase in water injection would result in a payout time of approximately 8 months with oil at US$25/bbl.

E. **Technology Transfer**

The single well injectivity test has been presented and reported to the Stripper Well Consortium. A paper has been written which will be presented at the SPE/DOE Fourteenth Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 17-21, 2004.[3] A copy of the SPE paper is included with this report. Additional technology transfer activities will be performed as allowed.

Conclusions

1. Fluid analysis and core displacement testing using actual reservoir core and fluids and field injectivity testing are good prediction tools to estimate the relative increase by chemical injection into a well to increase injectivity. Water injection rate was increased 220% in the field compared to 320% in linear coreflood using alkali plus surfactant and 130% with radial coreflood using alkali plus surfactant plus polymer.

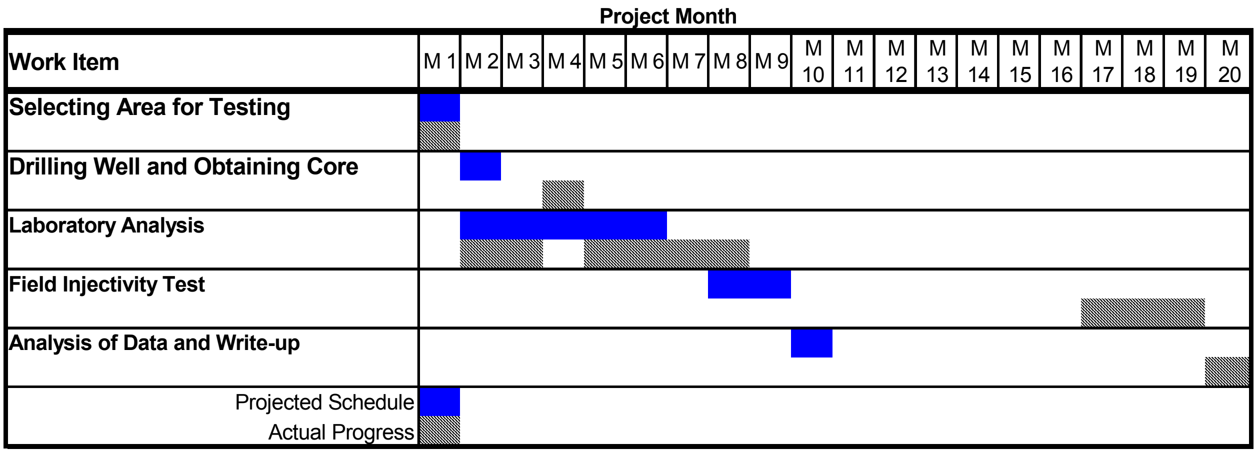
2. A properly designed alkaline-surfactant solution has the ability to significantly increase the effective permeability to water and, therefore, increase injectivity.

3. While the injection process is relatively simple, tight quality control is needed to maintain the consistency of the mixture during the long treatment period.

4. The alkaline-surfactant treatment process offers a relatively inexpensive option for small and large producers for increasing the long term injectivity of injection wells.

Project Schedule and Budget

The project is complete and within budget.



Actual expenditures are compared with the budgeted expenditures in Table 4.

Table 4
Big Sinking Actual and Budgeted Expenditures

Expenditure Category	Budgeted	Actual	Cost Share
Selecting Area for Testing	$ 5,000	$ 5,000	$ 5,000
Drilling Well and Coring	$ 38,000	$ 34,921	$ 34,921
Laboratory Program	$110,000	$110,000	$ 11,000
Injectivity Field Test	$ 10,000	$ 37,825	$ 37,825
Information Dissemination	$ 5,000	$ 5,000	$ 5,000
Travel for Presentations as of 1-31-04	$ 4,000	$ 1,782	$ 1,782
Total	$172,000	$194,528	$ 95,528
% Cost Share			49%

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ADVANCED TECHNOLOGY FOR INFILL AND RECOMPLETION CANDIDATE WELL SELECTION

Final Report

Reporting Period Start Date: May 15, 2002
Reporting Period End Date: December 31, 2003

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DISCLAIMER

ABSTRACT

The goal of this project was to develop and demonstrate technology for statistical analysis of production and injection data to characterize reservoir performance and assess infill drilling and recompletion potential in stripper oil well fields. Specific objectives of this project were to extend existing statistical methods from single-phase to multiphase, for application to waterflooded stripper oil fields, and to incorporate seismic data to improve both the coverage and accuracy of the statistical reservoir models employed. The improved technology was applied in the South Central Cut Bank Sand Unit (SCCBSU), Cut Bank Field, Montana, to determine enhancement recovery potential and strategies for this stripper well unit.

We investigated three techniques for rapid analysis of production and injection data. Moving window statistical methods are not suitable for analysis of the SCCBSU because the large variation in reservoir properties well-to-well are not consistent with assumptions of these methods. The Albertoni-Lake method indicated the presence of distant injector-producer pairs with strong connectivity, which is consistent with the channelized nature of the reservoir. However, the method does not have a predictive capability. A simulation-based regression approach proved successful in determining locations with significant infill potential in synthetic studies based on the SCCBSU. It was not entirely successful in the analysis of actual SCCBSU data, due to both problems with the production/injection database and limitations in the commercial regression software we employed.

The approximate, simulation-based regression approach described herein can provide a rapid, less-expensive alternative to conventional integrated reservoir studies for determining infill and recompletion potential, and can serve as a valuable reservoir management tool for operators of marginal stripper fields. This approach, as with any method that relies primarily upon well locations and production data, requires a complete and accurate production database for reliable use. We recommend that future research be directed towards continued development of the simulation-based regression approach, and recommend that it be validated in stripper gas reservoirs prior to further application in stripper oil reservoirs.

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EXECUTIVE SUMMARY

In this project we used statistical analysis of production data to characterize reservoir performance and to select locations for infill drilling or recompletion in stripper well fields. Integrated geological and reservoir engineering studies provide the best source of information for making reservoir management decisions. However, these studies are prohibitively time-consuming and expensive for many marginal stripper fields. Past studies have demonstrated that methods involving statistical analysis of readily available well location and production data, although less accurate than integrated studies, can be useful reservoir management tools in marginal reservoirs.

A specific objective of this project was to extend the existing Mosaic moving window statistical method, which has been used primarily in unconventional gas reservoirs, from single-phase to multiphase capability for application to waterflooded stripper well fields. A second objective was to incorporate seismic data to improve both the coverage and accuracy of the statistical reservoir models employed. The improved technology was to be applied in the South Central Cut Bank Sand Unit (SCCBSU), Cut Bank Field, Montana, to determine enhancement potential and strategies for this stripper well unit.

To incorporate seismic data into the statistical analyses, we evaluated seismic attributes and well log porosities in the Lower Cut Bank sand to establish a correlation and to model the porosity distribution. The three seismic amplitude attributes extracted from the Cut Bank interval were maximum amplitude, mean amplitude, and root-mean-squared (rms) amplitude. The correlation between porosity and both mean amplitude and rms amplitude are poor. On the other hand, we found that the maximum amplitude varies inversely with porosity of the Cut Bank reservoir, with a correlation coefficient of 0.51. Good correlation between seismic amplitude and log porosity enables the use of seismic data to map porosity trends for use in production data analysis.

Since statistical methods rely primarily on well locations and production and injection data, it is critical to have a complete and accurate database if the results of the statistical analyses are to be useful and reliable. Locating, quality checking and organizing the production and injection data for the 70+ year history of the SCCBSU proved to be difficult and time-consuming. Despite considerable effort over a year's time, the database is still incomplete, due primarily to data loss because field operations changed hands over the unit's history. Production data exist by tract only for the first 30 years of unit history. Critically, only unit-wide production figures are available for the period from approximately 1960 to 1980. Lack of a complete production and injection database limits the effectiveness of statistical methods to reliably determine infill and recompletion potential in the Cut Bank field.

We attempted a Mosaic interpretation of the SCCBSU production and injection data. However, we did not observe good correlation between production indicators and geological trends, due in part to problems with the production and injection database. In addition, we determined that the Mosaic method is not suitable for analysis of the SCCBSU because the large variation in reservoir properties well-to-well are not consistent with a major assumption of the Mosaic technique, namely that reservoir properties are relatively uniform in local windows of 5 to 20 wells.

Therefore, we employed a second technique, the Albertoni-Lake (AL) method, to interpret the production-injection performance of wells in the Lower Cut Bank reservoir of the SCCBSU. The technique, which uses only production and injection rate data, uses a constrained multivariate linear regression analysis to provide information about permeability trends and the presence of transmissibility barriers. The method indicated the presence of distant injector-producer pairs with strong connectivity, which is consistent with the channelized nature of the reservoir. Unfortunately, the method does not have a predictive capability. Thus, while we might be able to qualitatively infer potential infill well locations, the method does not provide a means of quantitatively assessing potential infill incremental recovery.

Next, we employed a third method, a simulation-based regression approach that we have developed for application in unconventional gas reservoirs. The approach uses reservoir simulation with automatic history matching to invert production and injection data to determine the permeability distribution. The reservoir simulation model and the resultant permeability distribution are used in an automated procedure to determine quantitatively the infill potential throughout the reservoir. The method differs from conventional reservoir simulation studies in several respects; the greatest difference is that we use only readily available data in constructing the simulation data set. Using an approximate data set results in similar time and cost requirements as for a Mosaic statistical analysis. The results are also necessarily approximate, but tests in other studies have demonstrated that, because we are using a simulator as the reservoir model, the results are more accurate than those from Mosaic.

We tested the simulation-based regression approach in several synthetic cases derived from the SCCBSU. The method was successful in recovering the approximate permeability distribution and determining locations in the unit with significant infill potential. Locations with infill potential correlated with geological trends; the greatest potential existed in incompletely swept channel deposits. Analysis of actual SCCBSU production and injection data was not completely successful, due both to problems with the production and injection database and limitations in the commercial automatic history matching software that we used. While we were able to map infill potential for the SCCBSU, the estimates possess considerable uncertainty and further study is required to verify their reliability.

Based on our research, we conclude that the simulation-based regression approach is superior to Mosaic for rapid assessment of infill potential, and that it can be a valuable reservoir management tool for operators of marginal stripper fields. However, this approach, as with any statistical method that relies primarily upon well locations and production data, requires a complete and accurate production database for reliable use. We recommend that future research be directed towards continued development of the simulation-based regression approach, with a focus on fit-for-purpose regression technology. We recommend that the approach be further validated in stripper gas reservoirs prior to additional application in stripper oil reservoirs.

INTRODUCTION

Quantifying the remaining potential in marginal oil and gas fields and basins is usually difficult, due to (1) high vertical and lateral variability in rock quality and connectivity; (2) variable completion and stimulation practices; (3) inconsistent well spacing; and (4) inadequate databases for reservoir characterization. The most accurate assessment of performance enhancement potential in such fields is a detailed, integrated reservoir evaluation using geophysical, geological and engineering data and interpretations. This requires compiling a detailed database, developing a geological model, estimating distributions of static reservoir properties such as porosity and permeability, constructing and calibrating a simulation model, and finally, using the model to predict and optimize performance.

Unfortunately, integrated studies are prohibitively time-consuming and expensive for stripper oil and gas fields, and they are impractical for independents with limited staff. In addition, there are often insufficient data for these studies. Hence, there is a need for less-demanding methods that characterize and predict heterogeneity and production variability. As an alternative approach to conducting detailed studies, various authors have used empirical or statistical analyses to model variable well performance (Voneiff and Cipolla, 1996; Reese, 1996; Hudson *et al.*, 2001; and Guan *et al.*, 2002). Most are based solely on well location, production and time data. Mosaic Technology[5] is an advanced technique that uses a model-based 4D regression of production *vs.* virgin productivity, cumulative production, and well spacing. A field is evaluated not as one single study, but as a mosaic of overlapping local studies. This technique can qualitatively indicate the degree of reservoir heterogeneity, pinpointing areas with rework or infill potential.

The statistical methods for production data analysis mentioned above have been developed primarily for depletion processes in gas reservoirs. In this project, researchers from Texas A&M University and MGV Energy endeavored to develop improved technology for rapidly assessing infill and recompletion potential in marginal oil fields. This requires extending the technology to include multiphase displacement processes, to allow application to waterflooding projects, where many stripper oil wells occur. Since Mosaic and other moving window methods are based primarily on analysis of production data, they can predict infill potential at only those locations near existing wells. Thus, another goal of the project was to enhance the statistical methods by incorporating seismic data, which has significant potential due to its large coverage and because such data can be related to interwell reservoir properties.

In conjunction with an operating company, Quicksilver Resources, we sought to demonstrate the utility of enhanced production data analysis in stripper oil and gas fields by applying the enhanced procedures in South Central Cut Bank Sand Unit (SCCBSU) of Cut Bank Field, Montana. Much of this unit has been waterflooded and most active wells produce less than 5 STB/D. A primary objective of the project was to determine the infill or recompletion potential for this unit.

OBJECTIVES

The specific project objectives were to:

- extend existing statistical methods from single-phase to multiphase for application to waterflooded stripper well fields;
- incorporate seismic data to improve both the coverage and accuracy of the statistical reservoir models employed; and
- apply the developed method to characterize reservoir performance, select locations for infill drilling, and target wells for reservoir recompletion in the Cut Bank stripper well field.

FIELD OVERVIEW

Cut Bank field, located in Glacier, Pondera, and Toole Counties, northwest Montana **(Fig. 1a),** was discovered in 1931. Cut Bank oil field is a long, narrow oil-leg on the west side of a larger stratigraphic trap on the west flank of the Kevin-Sunburst Dome. Production in the Cut Bank field is primarily from the Lower Cretaceous Cut Bank Sand, which is a fluvial sandstone deposit **(Fig. 1b and Fig. 2).** The oil field is 30 miles long and ranges in width from less than 2 miles near the northern end to about 6 miles near the southern end. The gas-oil contact of the Cut Bank sandstone is at approximately +1,040 ft.. At the north margin of the field, the Cut Bank oil/water contact is tilted, cutting across structural contours from +1,300 to +600 ft from the west to northeast **(Fig. 3).**

The Cut Bank Sand is the most important producing unit in the Cut Bank oil field. It is a braided-to-meandering fluvial sandstone deposit (Shelton, 1969; Weimer, 1982; Berkhouse, 1985; Horkowitz, 1987; and Hopkins, 1993) that varies in thickness and pinches out against the Ellis Group on the east, forming a stratigraphic trap. The Cut Bank Sand is comprised of upward fining sands with interbedded shales. Thickness of the unit ranges from to more than 80 ft on the west to zero at the pinchout on the east. Cut Bank sandstones are generally medium- to coarse-grained litharenites in which the lithic component comprises a wide range of chert and silicified sedimentary rock fragments. On the basis of outcrop studies, Horkowitz (1987) described the principal detrital constituents of the Cut Bank sandstone as quartz, silicified carbonate clasts, and argillaceous chert clasts **(Fig. 4).** Chert content of the sandstone may exceed 50%. Texture ranges from conglomerate to fine-grained sand, and porosity and permeability vary appreciably, both laterally and vertically. The highest porosity and permeability occur in medium-grained, conglomerate-free, cherty sand (Cupps, 1967). Because of wide variation in porosity and other reservoir properties, oil saturation is very irregular.

The Cut Bank Sand is composed of two members, the Upper and Lower Cut Bank Sand (Fig. 2). The boundary between the upper and lower sands varies from gradational to abrupt. The lower sand is the main producing horizon. It generally has the characteristics of a blanket sand that averages approximately 17 ft thick. The average porosity of the pay section is 14%, and permeability ranges from 10 md to 1,500 md, with the average being approximately 50 md (Matthies, 1962).

The Upper Cut Bank sand is thinner and not as wide spread as the lower sand, and it produces only locally. Interpretation of the Upper Cut Bank sandstone is based mainly on log analysis. It is composed of fairly clean, uniform, fine- to medium-grained sand (Hill, 1989). Unlike the Lower Cut Bank Sand, a basal conglomerate is rare, and when it is present it is quite thin.

The South Central Cut Bank Sand Unit (SCCBSU), focus of this study, produces oil from Cut Bank sands at an average depth of 2,850 ft, or +900 ft elevation above mean sea level **(Fig. 5).** Primary production and waterflood projects have yielded approximately 43 million bbls of the 126 million bbls of oil originally in place (OOIP) in the complex, heterogeneous reservoirs. Of the OOIP, 18.5 % was recovered by primary means. The SCCBSU water flood program was started in May 1963 and is still operating and expanding **(Fig. 6).** Daily production has declined to less than 5 STB/day in most active wells. Secondary recovery accounts for an additional 5% of the OOIP. At present, there are 277 wells in the SCCBSU area, of which 55 are active producers, 29 are active injectors, and 194 wells are idle. The current average well spacing is 92 acres/well.

Hardy and Treckman (1996) identified a 2-4 ft thick bentonite named the "Tin Roof" at the base of the Moulton (top of Sunburst) (Fig. 2). This layer is absent over part of the Cut Bank Unit area, where a major incised valley is present **(Fig. 7).** The incised valley is 1 to 1.5 mi wide and is at least 150 ft deep. The valley fill creates stratigraphic trapping potential in the Sunburst and, possibly, in upper Cut Bank sands.

In 1998, a 3-D seismic survey was acquired over an 8-mi^2 area of Cut Bank field to improve the ongoing waterflood program. The 3-D seismic data indicated that reservoir compartmentalization is controlled by lateral and vertical facies changes, not by faults or tectonic features (DeAngelo and Hardage, 2001). Major (and some smaller) channel-fill sandstones were delineated. According to DeAngelo and Hardage (2001) the "Tin Roof" bentonite, where present, appears to dampen the seismic reflectors below it, resulting in reduced seismic clarity of the lower Cut Bank sand. QRI drilled 5 new wells on the basis of the seismic interpretation. These new wells experienced oil production rates and watercuts similar to existing wells in the field.

DATABASE

The reservoir seismic database covers an 8-mi^2 region of the Cut Bank field. The well log database includes 275 wells located in the SCCBSU, NCCBSU, NWCBSU and TRIBAL units of Cut Bank field. The geophysical log suite varies among wells; log suites available in the database are combinations of gamma ray, density porosity, neutron porosity and other curves, such as old gamma ray neutron, resistivity, and spontaneous potential. In addition, core analyses are available for 11 wells. Upon reviewing the content and quality of data files, we concluded that the available velocity data were insufficient for the intended analysis. Therefore, we obtained additional well logs from

Riley Electric Log Inc., and Quicksilver Resources had them digitized. Production history data are available for 194 wells, not including injection wells and wells with only water production data.

RESULTS AND DISCUSSION

RESERVOIR CHARACTERIZATION

The primary objective of this project was to develop statistical methods for analyzing production and injection data for rapid assessment of infill potential in marginal oil reservoirs for which a complete integrated reservoir study cannot be afforded. It was necessary to conduct a reservoir characterization study in this study, however, to provide a basis for validation of the statistical methods. Another objective was to extend existing statistical methods to incorporate seismic data. This required the integration of seismic and petrophysical data, which we describe below.

Facies Analysis

Commonly, fluvial reservoirs are highly heterogeneous, with barriers or baffles to fluid flow within sand bodies that can be simple or highly complex in terms of three-dimensional geometries. Therefore, it is critical that a full assessment of internal sedimentary structures and hierarchies is determined and that potential compartments are well defined. Integration of geologic and engineering data can be used to identify reservoir heterogeneities responsible for entrapment of bypassed oil.

Integrating geologic and engineering data to identify heterogeneities in the subsurface involves several key steps, including:

(1) determination of reservoir architecture;

(2) investigation of the trends in reservoir fluid flow; and

(3) integration of fluid flow-trends with reservoir architecture.

To accomplish these steps, we evaluated maps (gross sandstone, log facies, percent sandstone, and porosity) and cross sections to establish a reliable reservoir stratigraphic model and to clarify reservoir architecture. Two maps, gross sandstone and net thickness, were provided by Quicksilver Resources; the remainder were produced in this project.

We began by refining the interpretation of the Cut Bank Sand base and top in well logs obtained from Quicksilver Resources and Internet Resources (Montana Oil and Gas Commission). The basal Cut Bank Sand contact is sharp in all the wells, but identifying the upper boundary is challenging. We used gamma ray (GR) character to produce a log-pattern (electrofacies) facies map of the more continuous Lower Cut Bank Sandstone member. Cut Bank Sand log patterns are blocky in the mid-channel deposits and upward fining or serrated at the channel margins. In the interchannel, floodplains areas, the thickness decreases markedly and the log patterns are serrated or sometimes upward-fining.

Overlaying the GR logs on a gross sand thickness map allows assessment of the reservoir architecture - geometry, size, vertical contacts, bedding characteristics, and thickness. We also used this technique to map porosity distributions in the Lower Cut Bank Sandstone throughout the SCCBSU area.

Porosity

One aim of this project was to demonstrate the value of seismic data for predicting hydrocarbon production. Seismic-based porosity predictions are one way to incorporate the seismic data into a relevant reservoir model. Some data analysis is required, however, before seismic-determined porosities can be calculated. In particular, seismic attributes and well log porosities must be compared to demonstrate any relationships and to model the porosity distribution throughout the field. Normally, both seismic attributes and log properties are averaged for a stratigraphic interval. The objective is to have a pair of attributes and log properties values for each well that intersects the layer so that relationships between these quantities can be determined. Therefore, it is important to construct a representative model of reservoir porosity from well logs.

Core data were used to calibrate and refine the interpretation from well logs. The available core porosity data were cross-plotted with log-derived porosity on a well-by-well basis. Most of the wells in the Cut Bank field have a density porosity curve. Core data are available from 6 wells located in the northern part of seismic survey. There are core data from a few other wells that we could not use for calibration because of the absence of density logs in these wells. **Table 1** summarizes the results of correlating core and density porosity data for the wells that have both types of data. To reduce the degree of scatter, a running average was applied to the core porosities. Core porosity curves were depth shifted to match with log depths using the gamma-ray curves.

Table 1. Summary of core porosity and density porosity calibration through cross-plotting.

Well #	Core data interval, ft	Available log curves	Depth shift, ft, (- downward, + upward)	Correl. Coef. - R	Relationship between core porosity and density porosity
37-7	2825-2855	GR, CALI, SP, Resistivity, Neutron Porosity, Density Porosity	3	0.9581	Core por=0.060712+0.508972*Density por
33-5	2830-2855	GR, Density Porosity	1	0.687675	Core por=0.090729+0.411721*Density por
19B-3X	2782-2808	GR, Density Porosity	-1.5	0.778207	Core por=0.041697+0.797283*Density por
39-1X	2923-2942	GR, Density Porosity	-3	0.070561	Core por=0.037309+0.879690*Density por
36-5	2932-2957	GR, Density Porosity	-2	0.748487	Core por=0.024393+0.82846*Density por
22-6	2784-2805	GR, Density Porosity	-3	0.796005	Core por=0.041014+0.658383*Density por

The results **(**Table 1**)** show that the correlation coefficient is low in all the wells except Well 37-7 **(Fig. 8).** When we applied the relationship between core porosity and density porosity from that well to other wells, it gave net pay average porosities of approximately 11 pu (porosity units). This value is 3 pu lower than the reported field net pay average porosity value from literature and reports supplied by Quicksilver Resources. In previous studies, net pay was defined based on a 10% porosity cutoff. We evaluated the appropriateness of a 10% porosity cutoff by cross plotting the available porosity and permeability data from 13 core reports from the Cut Bank field. There is a rather strong change in the behavior of the data, between data below and those above the 10% porosity line **(Fig. 9).**

In an ideal case, there should be a one-to-one relationship between core porosity and density porosity. **Fig. 10** shows the averaged core porosity vs. density porosity plot for all the wells that have core data. Wells 36-5 and 37-7 fall near the line, indicating good correlation. However, in Wells 33-5 and 39-1X, core porosity is consistently higher than density porosity. Based on core report summaries, cores from these two wells include abundant heavy minerals. This may also be the reason for poor agreement for wells 19B-3X, 36-1, and 22-6, where the log porosity underestimates the core-derived value. We conclude that the presence of heavy minerals causes the density log to be an unreliable porosity predictor.

Because the density log does not appear to give reliable porosity estimates, we examined porosity in wells that also had a neutron log. The combination of density and neutron logs gives porosity estimates that are less sensitive to lithologic variations than does the density porosity alone. There are 21 wells in the SCCBSU area that include both density and neutron porosity logs. The neutron-density average porosity (PHIA) value is close to the field-wide average (14%) reported in literature and reports **(Fig. 11).** Therefore, we decided to use PHIA values for the log porosity-to-seismic porosity calibration.

Integration of Seismic and Well Log Data

The critical step in seismic-guided log-property mapping is having accurate time-to-depth relationships. We estimated velocities from density logs using the Gardner equation ($\rho=cV^{\alpha}$, where $\alpha=0.21$ and $c=0.35$). The Gardner equation parameters (α and c) were estimated by combining data from 4 wells that have density logs and either sonic log or a borehole seismic report available.

Seismic velocity estimates determined from VSP data are available for one well (Well 54-8) in the study area, and this allows a check of depth-time relationships determined from log data alone. The two approaches compared favorably in the southwest area, but in the northeast part of the seismic survey area, the VSP data produced a significantly different depth-time relationship. Specifically, the difference between the estimated two-way traveltime at the relevant Cut Bank formation was of about 25 msec.

Thus, to tie seismic and well data, we used VSP (Well 54-8) data for the south and southwest parts of the seismic survey area. Sonic data derived from the density (Well 37-7) were used for the northeast area.

We generated synthetic seismograms using the standard convolutional model that convolves an estimated wavelet and a reflection coefficient series. The latter was calculated from impedance contrasts determined from sonic and density log. The objective is to correlate the reflections that we expect the formations to create (the synthetic) to the reflections in the seismic data. The seismic can then be interpreted accurately and compared directly to log measurements.

We integrated seismic and well log data in the Cut Bank field to determine which, if any, seismic attributes can be used to map reservoir properties and can be incorporated into production-based statistical analysis. The variations observed in seismic attributes such as amplitude should be a function of variations in reservoir parameters, including porosity. To test this hypothesis in the Cut Bank field, we compared seismic attributes with well log porosities to establish a correlation and to model the porosity distribution throughout the field.

By plotting the average Cut Bank sandstone porosity at each well against the seismic amplitude at that well, the nature and strength of the relation was investigated. We used average neutron-density porosity (PHIA) values for the log porosity from 21 wells.

The three seismic amplitude attributes extracted from the Cut Bank interval were maximum amplitude, mean amplitude, and root-mean-squared (rms) amplitude. The correlation between porosity and both mean amplitude and rms amplitude are poor. On the other hand, we found that the maximum amplitude varies inversely with porosity of the Cut Bank reservoir **(Fig. 12).** The regression had a value of $R^2 = 0.51$ when fitting the maximum amplitude to the average porosity of net pay (PHIA > 10%). Two points, wells 49-10 and 39-4 (polygons in **Figs. 12 and 13**), were excluded in obtaining this relationship. This reasonably good correlation between seismic amplitude and log porosity enables the use of seismic data to map porosity trends for use in production data analysis.

The maximum amplitude at the Well 49-10, located at the center of the seismic survey area, is anomalously high compared to the average log porosity (PHIA). This high value may result from an inconsistent interpretation of the base of the Lower Cut Bank strata (Ellis top) in this area. This horizon is at the zero crossing above positive amplitudes (peaks) throughout all of the seismic survey **(Fig. 14),** with the exception of the problem area of Well 49-10 **(Fig. 15).** Another cause may be the location of this well adjacent to the western edge of the Lower Cretaceous Gorge. Well 39-4 is also located near the western edge of the Lower Cretaceous Gorge. In this well the maximum amplitude value again under-predicts the porosity. Here, also, another explanation may be an inconsistency in the interpretation and stratigraphic ties of the Lower Cut Bank interval in well log and seismic data **(Fig. 16).**

Evaluation of Geological Maps

Net-thickness maps of lower Cut Bank sand in the SCCBSU area were prepared separately by Unocal, the prior operator of the field, and the QRI/BEG (Quicksilver Resources/Bureau of Economic Geology) team. The QRI/BEG thickness map incorporated both seismic amplitude data and well log data. By superposing the QRI/BEG net sand thickness map on the seismic average absolute amplitude map, we found that regions interpreted as higher average absolute amplitude correspond to higher estimated net sand thickness, suggesting that QRI/BEG mapping was guided by seismic amplitude occurrences and trends **(Fig. 17).** However, we found that there is no correlation between the measured net sand thickness from the well logs (based on 60% GR and 10% porosity cutoffs) and the average absolute amplitude values **(Fig. 18).** Therefore, we infer that there are limits on the accuracy of the QRI/BEG interpretation. Also, there are significant differences between the QRI/BEG average absolute amplitude map and the earlier UNOCAL net sand thickness map **(Fig. 19).**

Interpretation of net sand thickness in the area of Well 33-1 differs greatly on the UNOCAL and QRI/BEG maps (Figs. 17 and 19). Production data for the SCCBSU 33-1 record a rapid increase in oil production in response to waterflooding. Currently there are no logs available for this well, precluding any direct determination of sand thickness to assess which map is more accurate.

However, we used results of the QRI 1999 five-well drilling program to compare UNOCAL's and QRI/BEG's net sand thickness maps to the Cut Bank thicknesses encountered in wells **(Table 2).** In Wells 49-14, 38-13, and 37-7, there is large disagreement among the net sand thickness values from three different sources (UNOCAL map, QRI/BEG map and actual, from well logs), which demonstrates the uncertainty associated with indirect methods of thickness determination and reservoir mapping.

Table 2. Comparison of mapped and actual net sand thicknesses from QRI's 1999 five-well drilling program.

Well (SCCBSU)	Unocal Mapped H (ft)	QRI/BEG Mapped H (ft)	Actual H (ft) (from new well logs)
49-14	6	20+	0
38-13	6	20+	23
54-10	15+	30+	16
37-7	6	25+	26
47-7	25+	30+	34

Seismic and well-log cross sections (W-to-E) **(Figs. 20 and 21)** were made through the SCCBSU 49-14 well location, where there was a large error in predicted thickness. The objective was to determine why the QRI/BEG mapping predicted so much sand in an area where no sand was present. As mentioned, a high average absolute amplitude was found to correspond to high net sand thickness values on the QRI/BEG net sand thickness map in all locations, except that of Well 49-14. At this well, the seismic amplitude is anomalously high and does not match expected thickness values. Moreover, this well is near Well 49-10, where the maximum amplitude is anomalously high compared to the average log porosity (PHIA), as was discussed earlier (Fig. 12). We conclude that this high porosity value may result from an inconsistent seismic pick of the base of the Lower Cut Bank strata (Ellis top) in this area, owing to locally complex seismic responses.

PRODUCTION AND INJECTION DATA ANALYSIS

The primary objectives of this project were to (1) extend an existing statistical analysis technique, the Mosaic moving window method, which had been developed for gas reservoirs, so it could be used to rapidly assess infill potential in stripper oil fields and (2) demonstrate its utility by applying it in South Central Cut Bank Unit. In the course of our investigation, we discovered limitations in applicability of the Mosaic method to the Cut Bank field, discussed below. Thus, we investigated the use of two alternative methods, the Albertoni and Lake (2003) method and a simulation-based inversion method. The most important data, and in some cases the only data, required for each of these methods are well locations and production and injection data. In the sections that follow we first discuss the assembly of the well and production/injection database. We then discuss application of each of the three methods to the Cut Bank field.

Production and Injection Database

1. Database creation:

   Locating, quality checking and organizing the production and injection data for the SCCBSU proved to be much more difficult than anticipated. The unit has a long history (beginning in the 1930's), and operations have changed hands over the years, resulting in data loss. Data had to be acquired from multiple sources, and for some years, entered by hand from paper records. Quicksilver designed an Access database specifically for the SCCBSU, and began loading the production and injection data shortly after project initiation. Problems associated with locating and reconciling data slowed database completion and project progress significantly; the final database used for the project was not completed until over a year after project initiation.

   Although we have loaded all production and injection that we were able to locate, the database is far from as complete as we would like. There are no significant amounts of recorded gas production data. The database contains individual-well injection data for the entire waterflood period. However, it contains individual-well production data only from the early 1980's forward. Early production data from inception of the field in 1932 to approximately 1960 exists by tract (or lease) rather than by individual well. Between about 1960 and the early 1980's, the detail, quantity and quality of production data are variable, ranging from unit-wide information only during the 1960's to sporadic and incomplete individual-well production data during the 1970's. Individual-well data becomes more reliable during and after the 1980's, when Montana's oil and gas regulatory agency began requiring the reporting of individual-well production volumes. Still, these individual-well volumes are based on allocation of gathering center volumes using periodic well production tests.

Lack of a complete production and injection database will limit the effectiveness of statistical methods to reliably determine infill and recompletion potential in the Cut Bank field, since these statistical methods rely primarily on interpretation of individual-well production and injection data.

2. Well types:

   There are approximately 370 wells and 13 operators in the SCCBSU unit. The largest operator, Quicksilver Resources, Inc., operates 78.3% of the SCCBSU wells. **Table 3** shows information on well types. About 62% of the wells are oil production wells and 34% are injection wells.

Table 3 – Well Types in SCCBSU

Well Type	Number of Wells	Percentage, %
Dry Hole	7	1.90
Gas	3	0.82
Injection, EOR	126	34.24
Injection, Indian Lands	1	0.27
Oil	228	61.96
Total: 5 well types	**369 wells**	**100 %**

3. Waterflooding history:

   A pilot waterflood in the Cut Bank Sand reservoir was started in 1952 in the center of a unitized 640-acre tract. The first phase of waterflood development began in the late-1950's or early 1960's, and was completed in 1962 using a five-spot injection pattern on several tracts in the southern part of the field. Waterflood area expansion projects were completed in 1966, 1969, 1970, 1976, 1981, 1983, 1984, and 1988.

4. Production and injection data review:

   An examination of the production and injection data reveals that fluid injection far exceeded fluid production from 1970 to 2002 **(Fig. 22).** The fluid production from January 1970 to July 1972 is very small because of gaps in the production database during that time. **Fig. 23** shows the correlation between fluid injection and fluid production for SCCBSU. Although a trend is apparent, the data do not correlate well (R^2 is 0.27). **Fig. 24** shows the relationship between water injection and oil production over the period 1970 to 2000. Correlation between field water injection and oil production is only marginal, and the water injection far exceeds the oil production. At this time we cannot explain why the fluid injection greatly exceeds the fluid production, although we are investigating the cause. Inability to explain and account for this phenomenon may limit the effectiveness of the Mosaic statistical analysis.

Based on Figs. 22-24, it does not appear that waterflooding has been particularly effective in the South Central Cut Bank Unit. However, there are instances of apparently significant waterflood response for selected wells **(Figs. 25 and 26)**.

The Mosaic Technique

The Mosaic technique was originally developed by MGV Energy Inc. for determination of infill potential in unconventional gas reservoirs. The technique is an extension of the method described by Voneiff and Cipolla (1996), and is described in Guan *et al.* (2002). It consists of a multitude of local analyses, each in an areal window centered around an existing well. Unlike the method of Voneiff and Cipolla, however, the Mosaic technique employs a more rigorous, model-based analysis in each moving window. The model is based on a combination of the material balance equation and the pseudosteady state flow equation, simplified by assuming that many properties are constant within an individual window. The result is a linear, multivariate (4D) regression equation that is applied within each window:

$$BY = f(VBY, G_p/A, A)$$

where

BY = best year, the best 12 consecutive months of production divided by 12. BY has been demonstrated to correlate well with long-term production (Voneiff and Cipolla, 1996). BY is used as a proxy for production rate in the pseudosteady state flow equation.

VBY = virgin best year, the BY of a well at virgin conditions. Depletion effects are removed by computing the BY of a local area at a time before depletion using a 2D regression of BY *vs.* well start date. VBY is used as a proxy for *kh* in the pseudosteady state flow equation.

Gp/A = cumulative production divided by well spacing.

A = Well spacing, area of Voronoi polygon around each well based on well locations. Used as a proxy for drainage area in the pseudosteady state flow equation and material balance equation.

Regression coefficients for each window are determined by regressing these parameters for the wells within each window. The windows are limited in size, e.g., 3000 acres, and generally contain 5 to 20 wells. If the number of wells in a window is less than a minimum value, e.g., 3-5, a regional or global regression is used instead of a local regression.

Once the regression equation coefficients are determined for each window, performance can be estimated for infill wells by substituting the appropriate values for candidate infill well conditions (well spacing, G_p/A, VBY). The result of this analysis is a prediction of BY for a new infill well offsetting each existing well. Results are approximate, due to the assumptions inherent in the procedure, although still useful. As reported by Guan *et al.* (2002), Mosaic analysis can reliably determine the infill potential for groups of wells, often to within 10%. However, individual well predictions can be off by 30% to 50% in some cases. When geological data are available, there is often agreement between geological features and trends in production indicators predicted by the Mosaic analysis.

The primary advantages of the moving window technique are its speed and its reliance upon only well location and production data. It is routinely used to conduct infill screening studies of projects consisting of 1000's of wells and can be used to evaluate an entire basin in a few man-days.

Since the Mosaic technique was designed for unconventional gas reservoirs, one of our objectives was to incorporate multiphase flow capability so the technique could be applied to waterflooded stripper oil fields. Since the Mosaic correlation equation does not include a term related to pore volume, another objective was to provide for the incorporation of other types of data, such as seismic data, that can serve as a proxy for porosity or porosity-thickness in the multidimensional regression.

Our first step was to change all the queries and spreadsheets of the Mosaic software from single-phase gas to single-phase oil. There are 10 spreadsheets and about 40 queries in the Mosaic software. We then began a preliminary Mosaic analysis of the SCCBSU production data.

Production Trends Analysis

Standard practice in Mosaic studies is integration of production trends with reservoir architecture and properties to help in understanding reservoir performance. Correlation of production with location helps to establish the sensitivity of production to geological features. This correlation was attempted in SCCBSU by comparing Lower Cut Bank Sandstone production performance maps with geologic and reservoir-quality maps, such as gross thickness, structure, net thickness, net-to-gross ratio and average porosity.

Production indicator maps, made on a well-by-well and a tract-by-tract basis, were used to establish production trends in the Lower Cut Bank sand in the SCCBSU. Well-by-well production data after 1972 were used to generate several typical Mosaic production indicator maps including:

- best year of oil production (best consecutive 12 months production divided by 12);
- virgin best year (best year of the well corrected for the effects of depletion);
- infill best year (calculated best year for an infill wells offsetting each well); and
- cumulative production, by well.

Tract-by-tract production data cover the periods from 1932 to 1966 and from 1972 to 2000. Indicator maps made from these data included:

- best year production (best consecutive 12 months production divided by 12);
- production/tract area (STB per acre);
- cumulative oil production;
- cumulative gas production;
- cumulative water production;

- cumulative water injection; and
- difference between injected water and total produced liquid (oil and water).

We attempted to correlate the areas of good and poor production response to features on the geological maps. In general, we did not observe good correlation. Interpretation was hindered by disagreement between geological maps obtained from two different sources and by problems with production and injection data, both discussed previously, and by the general character of reservoir property distributions in the Cut Bank sand. There are two primary issues related to production and injection data. First, there is a significant amount of missing individual-well production data, which is required for the Mosaic technique. We have about 30 years with only data by tract and about 20 years with only data by unit. In addition, there is an unreasonably high ratio of cumulative water injected to liquid (oil and water) produced. We have some concern that a significant amount of injection may have gone out of zone; however, this is difficult to confirm. Out-of-zone injection could significantly affect the accuracy of our interpretations and predictions.

Finally, we observed significant variation in reservoir properties well to well, such as net sand thickness (Figs. 17 and 19), due to the channelized nature of deposition in the Cut Bank sand. This violates one of the major assumptions of the Mosaic technique, namely that reservoir properties are relatively uniform in windows of 5 to 20 wells. Because of all these complications, particularly the latter, we concluded that further Mosaic analysis of the Cut Bank sand would most likely be unproductive. Therefore, we investigated two alternate techniques for statistical analysis of production and injection data.

The Albertoni-Lake Technique

We employed a new technique developed to quantify communication between wells to interpret the production-injection performance of wells in the Lower Cut Bank reservoir of the South Central Cut Bank Unit. The technique, which uses only production and injection rate data, uses a constrained multivariate linear regression analysis to provide information about permeability trends and the presence of transmissibility barriers (Albertoni and Lake, 2003). The Albertoni-Lake (AL) technique calculates the fraction of flow (λ) in a producer attributable to flow at an injector. The analysis is performed on a field-wide or regional basis and analyzes multiple well influences in a single step. It uses filters to account for the time lag and attenuation occurring between each injector-producer pair.

We subdivided the field into three study regions, namely, the north, north-central, and south regions and applied the AL method separately to each region. We considered only those periods in which the greatest number of producers and injectors were active with minimum breaks in production and/or injection at each well. The active wells were then further screened to 16 producers and 25 injectors using the criteria of highest rates and fewest rate disruptions.

The program calculates the λ's for each of the 400 injector-producer pairs in a region. The λ's calculated by the program are essentially vector quantities whose magnitudes and directions can be represented in an arrow plot (**Fig. 27**). The magnitude of λ is represented by the arrow length. The arrow points from the injection well towards the producer for which the λ is calculated.

Production Trends Analysis

Figs. 28-30 are the arrow plots overlain on the BEG-Quicksilver net-sand thickness map of the field for each region. There is a generally good correspondence between the calculated λ and the presence of net pay as indicated on the map; there are red or green colored regions between wells where λ is large and more blue where λ is small. The variability of the arrow lengths with direction suggests the connectivity is strongly anisotropic, favoring the orientations of the channel axes. The presence of distant injector-producer pairs with strong connectivity (e.g., Fig. 28) appears to reflect the channelized nature of the reservoir.

Figs. 28-30 show the more recent version of the net pay map, which was produced by Quicksilver Resources and the Bureau of Economic Geology (QRI/BEG). An older net pay map produced by Unocal, which shows the fluvial channels as more distinct, separated events **(Fig. 31),** shows a poorer comparison between net pay and the injector-producer connectivities. This suggests that the older map may be less accurate.

Further analysis of the λ's was performed to confirm their interpretation as a measure of connectivity, since the favorable comparison with the QRI/BEG map was subjective. We tested the relation of the λ's to oil production, for each producer in each region. In all three regions, there appears to be a proportionality between the maximum λ and the cumulative oil produced, N_p, (**Figs. 32-34**). This again suggests that the λ's are indeed measuring connectivity. However, this analysis is incomplete because it does not take injection rate into account.

Finally, we evaluated several production wells to determine if the weighted injection did, indeed, match the production profile. **Figs. 35 and 36** show typical results observed. First, there is a good match between the actual production of total fluids (blue diamonds) and the weighted sum of injector contributions (pink squares). Second, a significant mismatch occurs (blue triangles) when one of the injectors is excluded. This suggests, again, that the λ's are measuring interwell connectivity.

The AL method indicates that injector—producer influence reflects the channelized, elongate geometry of the reservoir. This gives rise to significant long-distance influence exerted by some injectors on producers. Such long-distance connections are incompatible with the assumption of using Mosaic and other, moving window methods. These methods require significant production influences to arise only from nearby wells. While the AL method does appear to be able to detect long-distance connectivity, unfortunately it does not have a predictive capability. Thus, while we might be able to qualitatively infer potential infill well locations, the method does not provide a means of quantitatively assessing potential infill incremental recovery. An alternative approach to both Mosaic and the Albertoni-Lake method is needed to fully assess infill potential in reservoirs such as the Cut Bank Sandstone.

Simulation-Based Regression Approach

As an alternative to Mosaic and other moving window methods, we have been investigating in other research projects the use of reservoir simulation combined with automatic history matching to rapidly assess infill-drilling potential in unconventional gas reservoirs. As described above, the Mosaic method combines the material balance equation with the pseudosteady state flow equation in a 4D regression of production data within each moving window. A reservoir simulator also combines material balance equations with flow equations, albeit with more rigor. Our approach is to use reservoir simulation combined with automatic history matching to regress production data, similar to the Mosaic approach. The difference is that we regress, or invert, production data to determine the permeability distribution. We then use the permeability distribution and an array of automated simulation predictions to determine infill drilling potential throughout the reservoir.

The likely immediate objection to this proposed approach is that, since it is based on reservoir simulation, it will require a complete reservoir data set, unlike the Mosaic technique. The complete reservoir data set will either not be available or will require a reservoir characterization study, which will increase the times and costs significantly and which will provide no advantage over conventional reservoir studies because it will be, in fact, just like any other reservoir study. This is not the case here.

Our objective is still rapid assessment of infill-drilling potential using only readily-available well locations and production data, thus providing approximate, statistical assessments for significantly less times and costs than conventional reservoir studies. To accomplish this we adopt several strategies. First, we do not conduct a reservoir characterization study. For data other than well locations and production data, we use only what are currently available. For example, if a net thickness map is available, we input it into the simulator; otherwise, we use an estimated average value of net thickness. Second, we use relatively coarse simulation grids, by conventional simulation standards. In conventional reservoir studies, we typically use fine grids because our scope is usually limited to a single reservoir. For infill-drilling studies in unconventional reservoirs, our scope is usually much larger, approaching basin scale in some cases. Thus, we use relatively coarse grids and fewer layers (often only one) to minimize run times and costs and to reduce the number of parameters in the regression. Third, we use different regression parameters than we use in conventional reservoir simulation studies. Instead of matching on individual cell values of reservoir properties (usually permeability), we match on constant values of permeability within the Voronoi regions around each well. Thus, the number of regression parameters is reduced to the number of wells. Fourth, we use different well controls and matching variables. In conventional reservoir simulation history matching, we usually fix the production of the primary hydrocarbon phase and match on reservoir pressure and production ratios, such as GOR and WOR. In the application of our proposed approach to unconventional gas reservoirs, we often have no reservoir pressure data. Thus, we control the wells using an estimated constant flowing bottomhole pressure (a reasonable assumption for low-rate gas wells) and match on production rates.

Using a reservoir simulator in an approximate way like this requires a change in mindset, which may be difficult for some engineers. Because of the assumptions and approximations we make, the results are approximate. However, our tests in single-phase, low-permeability gas reservoirs indicate that the new approach is more accurate than the Mosaic moving window method, with about the same amount of data, time and effort required. Thus, with this approach, in essence, we are using the reservoir simulator as an approximate, scoping tool.

There are a number of advantages to this simulation-based approach. First, it does not require the assumption of uniformity of reservoir properties in windows of 5 to 20 wells, as does the Mosaic method. Second, since it utilizes a reservoir description instead of simplified regression equations, seismic data and other types of geological information can be more readily incorporated than in moving window methods. This should improve the quality of the results and decrease the level of uncertainty. Third, the approach provides a means for gradual transition from preliminary scoping studies to more rigorous, conventional reservoir studies. As more data and interpretations are acquired, the model reservoir description can be updated and the regression repeated. Mosaic and other moving window methods do not provide an easy means for transitioning to more rigorous analyses. Finally, the method can be more-readily applied to stripper oil fields, such as the Cut Bank field, than moving window statistical methods, since reservoir simulators are already capable of modeling multiphase flow.

A key component of this alternative method is robust automatic history matching technology. While we have developed proprietary software for our work in unconventional gas reservoirs, we have elected to use SimOpt in our application to the Cut Bank field. SimOpt is an automatic history matching tool developed by Schlumberger and designed to work with the Eclipse family of reservoir simulation software. It uses mathematical techniques to vary specified reservoir parameters (permeability, in our case) to minimize the difference between observed and simulated production data. It can also take into account prior geological information, when available, in the regression.

Tests on Synthetic Cases

Because of the problems we had with the Cut Bank production data, we decided to first test the new approach on several synthetic cases derived from the SCCBSU. The purpose was to evaluate the capabilities of the software for the automatic history matching process as well as to test the ability to solve a problem where the solution is known beforehand. The synthetic model resembles the actual field in several respects. We used the structure map of the Lower Cut Bank sand, the net pay map from QRI/BEG, and a porosity map from log data. Core data were used to establish a porosity-permeability transform and to map permeability. This permeability map became the "known" permeability distribution for the purposes of testing the regression in the synthetic cases.

For each case, we generated 20 years of oil, gas and water production rates, water injection rates, and bottom hole flowing pressures with the synthetic model, and then performed a regression using SimOpt. We started with a constant permeability value for the entire field, which provides a rigorous test of the regression code. We then attempted to determine the "actual" permeability distribution by matching the synthetic production and injection data. Instead of matching on permeability in each simulation grid block, we matched on the uniform permeability value in the Voronoi region (region of grid cells closer to a well than any other well) surrounding each well, resulting in one matching parameter per well. Even though the resolution of the calculated permeability field would not be the same as the actual permeability field, the object of the regression was to obtain a permeability distribution that would resemble the one used to generate the observed data.

We started with small synthetic cases, all single layer, and increased the size with the successful completion of each case. The smaller cases, e.g., a 54-well case and a 112-well case, could be run on a PC. The computational and memory requirements of

SimOpt are significant, however, and we were required to run larger cases on a Unix workstation. The largest case we ran covered the entire central seismic area and included 192 wells. **Fig. 37** shows the simulation grid and the Voronoi permeability regions around each of the 192 wells in this model. The regression converged within 9 iterations, with a root-mean-square error decreasing from around 400 and to a value close to 100 **(Fig. 38). Fig. 39** compares the permeability map used to generate the observed data and the permeability map obtained after the regression. **Figs. 40** and **41** show the best and worst well matches obtained between the simulated results and the observed data. We consider the regression results to be good, especially given that we started with a uniform permeability distribution. Unfortunately, it took 8 hours of machine time per iteration and, thus, 72 total hours to achieve an acceptable match for this problem.

To determine infill-drilling potential, we made performance predictions with the reservoir simulation model and the permeability distribution resulting from the regression of production data. We first made a 20-year base case forecast in which we continue current operations, and then recorded the ultimate recovery. To determine the potential incremental recovery to be realized from drilling an infill well at a particular location, we made a 20-year projection in which we drill and produce one new well at the location (grid block) of interest, and then recorded the incremental recovery to be attributed to the drilling of this well. We then repeated this procedure for every grid block, using an automated procedure, to determine the incremental recovery to be realized from an infill well drilled at all possible locations (grid blocks) in the reservoir.

A map of infill incremental recovery is shown in **Fig. 42**. Visualization of infill potential in this way makes it immediately apparent that there is greater potential for infill drilling in the northwest portion of the field than in the southeast portion. Comparing the infill incremental recovery map to the net pay map (**Fig. 43**) and permeability map (Fig. 39b) indicates that greater infill potential tends to be located in areas of higher permeability and sand thickness corresponding to channel deposits. The procedure also takes into account proximity to existing wells as well as fluid saturations. Thus, the map reflects lower infill potential in areas of high water saturation near existing injection wells.

Since we have used a coarse permeability distribution in the regression (a constant permeability in the region around each well), the calculated permeability is not perfect. To determine the effect of this approximate permeability distribution on the estimation of infill potential, we also constructed an infill incremental recovery map (**Fig. 44**) using the original, “known” permeability distribution (Fig. 39a). The similarity between Figs. 42 and 44 indicates that the imperfect permeability distribution does not affect significantly the conclusions regarding which areas of the field offer the greatest infill potential.

Although the synthetic reservoir models were derived from the SCCBSU, the simulated production and injection performance do not necessarily closely resemble actual Cut Bank performance. In particular, the synthetic models do not experience the rapid water breakthrough, large ratio of water injection to fluid production, and low incremental waterflood recoveries that are observed in the SCCBSU. We attribute these waterflood performance characteristics to gravity segregation combined with generally higher permeability at the base of the Cut Bank sand (consistent with the generally upward-fining log signatures), neither of which are captured in the single-layer synthetic models. Nonetheless, these cases demonstrate the viability of the simulation-based approach, which was the objective of the synthetic modeling.

Analysis of Actual Cut Bank Production Data

With good results from the synthetic modeling, we next attempted to analyze the actual production and injection history from the central seismic area of the SCCBSU. The actual data set includes production and injection data for 172 wells for approximately 71 years of history, the last 40 years being the waterflood. Instead of starting with a uniform permeability distribution, we started the regression with an initial permeability distribution (**Fig. 45**) derived from a correlation between core porosity and permeability data.

We started with a 5-layer model, thinking it necessary to model gravity segregation and the vertical distribution of permeability in the Cut Bank sand if we were to match actual SCCBSU performance data well. This proved impossible, however, due primarily to software problems and limitations. The SimOpt software that we are using for automatic history matching is general-purpose software designed to manage efficiently up to 50 parameters in the regression. We are using more than 3 times this number of parameters and are, thus, stretching its capabilities significantly. In addition, with 71 years of history, iterations take considerably longer than the 8 hours per iteration required for the 20-year synthetic case, making the multi-layered analysis impractical.

Ultimately we conducted a single-layer analysis. This required a two-step process. In the first step we used pseudo relative permeability curves to obtain a rough match of the overall SCCBSU producing water-oil ratio. Using pseudo relative permeability curves reproduces the water bypassing effects due to gravity segregation and higher permeability near the base of the Cut Bank sand. **Figs. 46-48** show comparisons of simulated to observed performance on a field-wide basis.

The second step was to regress the production and injection data to refine the permeability distribution. The regression attempt was unsuccessful. It resulted in very little improvement in the match, and yielded formation permeabilities that were unreasonably high in parts of the reservoir. We attribute the inability to get a reasonable match to both software limitations and problems with the production and injection database. As mentioned previously, we are exceeding the recommended maximum number of regression parameters by more than a factor of 3. While this may limit the robustness of the solution, more importantly, it results in memory and computational requirements that make solutions intractable. We think the greater cause, however, is problems with the production and injection database, in particular, the lack of individual well production data. During the approximately 20-year period in which we have only unit-wide production, production is necessarily allocated among wells. This introduces the potential for significant error in individual-well production rates, which would obviously affect significantly the accuracy of results based on these individual-well data.

Thus, the model resulting from the field-wide match of water-oil ratio in step one (permeability map in Fig. 45 and match results in Figs. 46-48) represents our best model of the SCCBSU at this time. We ran our automated infill incremental recovery determination procedure using this model, which resulted in the map shown in **Fig. 49**. Examination of Fig. 49 indicates that greater infill potential occurs in the western portion of the region than in the east. This is reflective of higher water saturations in the eastern portion, due to the start of waterflood operations in the eastern portion 20 years prior to the start of waterflooding in the western portion. The large area colored in red, corresponding to a relatively uniform upper limit on infill recovery, in a consequence of the well constraints employed in the simulated projection runs. We specified a target oil rate of 200 STB/D for the new infill production well in the projections. The areas in red correspond to locations in which the new infill well was able to maintain the target rate over essentially the entire 5-year projection period. Areas of lower infill recovery in the midst of the red areas correspond to either lower pore volume or permeability, or proximity to injection wells.

Given the incomplete regression and problems with the production/injection database, we caution that there is considerable uncertainty in these results. Further study is required to select specific infill locations.

Discussion

We believe the simulation-based analysis of the actual SCCBSU data was not completely successful in large part due to problems and omissions in the production and injection database. We note that the other two methods that we employed, the Mosaic and the Albertoni-Lake methods, are also adversely affected. Any method that is based primarily on analysis of production and injection data, as these three methods are, will be adversely affected by inaccuracies in the production and injection database. We were not aware of the problems with the Cut Bank production data at the beginning of the project. In hindsight, it is clear that this was not the best field case for demonstrating application of these methods. We continue to believe that statistical methods for rapid assessment of infill and recompletion potential, particularly the simulation-based method that we have presented, can be valuable reservoir management tools for operators of marginal stripper fields. However, while they may cost significantly less than complete, integrated reservoir studies, they are not without costs. Time, effort and money must be spent in construction and quality control of the production database for the methods to be of use. The results can be no better than the quality of the data.

That we were able to match a synthetic model of the SCCBSU with 192 wells indicates the viability of our simulation-based methodology for rapid assessment of infill potential. Given its superiority over moving-window statistical methods, we recommend that future research in this area be focused on continued development and validation of the simulation-based regression approach. However, it may not be practical with the regression software technology that we are currently employing. Fit-for-purpose software may be required for this application, particularly for larger stripper fields with many more wells, which is our intended use of the methodology. Researchers in the Petroleum Engineering Department at Texas A&M University are currently working on a new generation of simulation regression tools that appear to be much more powerful and efficient than existing commercially available software.

Finally, based on our work in this and other research projects, we believe that greater benefit of the Mosaic and simulation-based regression techniques will be realized in unconventional and stripper gas reservoirs than stripper oil reservoirs, at least in the near term. Gas reservoirs are less often affected by multiphase flow, and they are less sensitive to other parameters such as PVT properties. Consequently, there are fewer degrees of freedom in the regression of gas reservoirs than oil reservoirs, particularly waterflooded oil reservoirs. We recommend that continued research on rapid infill assessment tools be directed towards gas reservoirs in the near term. Once the technology is well proven in stripper gas reservoirs, the focus can be shifted to the more complex stripper oil fields.

CONCLUSIONS

1. Maximum seismic amplitude varies inversely with well log porosity (R^2=0.51) in the Lower Cut Bank Sand. This correlation between seismic amplitude and log porosity enables the use of seismic data to map porosity trends for use in production data analysis.
2. Problems and omissions in the SCCBSU production database limit the effectiveness of all the rapid infill assessment techniques we investigated, since these techniques rely primarily on analysis of production and injection data. The SCCBSU production database is incomplete due to data loss as the unit changed operators during its history.
3. The Mosaic moving window statistical method is not suitable for analysis of SCCBSU production and injection data. The channelized nature of Cut Bank sand deposits results in significant variations in reservoir properties well to well, which are inconsistent with the Mosaic assumption of relative uniformity of reservoir properties in windows (local neighborhoods) of 5-20 wells.
4. Interwell connectivity evaluations, using the Albertoni and Lake (2003) method, give useful indications of well interconnection for the Cut Bank field. The connectivity appears to be strongly anisotropic and influenced by the fluvial geometry of the reservoir. The QRI/BEG net sand pay map gave better agreement with the connectivity maps than did the older, Unocal map.
5. The Albertoni and Lake method may provide a qualitative indication of possible infill well locations. However, it does not provide a means of assessing potential infill well incremental recovery.
6. The simulation-based regression approach appears to be superior to the Mosaic technique in rapidly assessing infill potential due to its (a) similar time and cost requirements, (b) greater accuracy, (c) ability to more readily incorporate other data types, and (d) multiphase capability.
7. In synthetic cases derived from the SCCBSU, the simulation-based regression approach successfully identified infill well locations with significant incremental

potential. Infill potential was concentrated in incompletely swept channel deposits.

8. Analysis of actual SCCBSU production and injection data using the simulation-based regression approach was unsuccessful, due to both problems with the SCCBSU production and injection database and limitations in existing commercially-available regression technology.
9. The simulation-based regression approach should be refined and proven on gas reservoirs before the technology is transferred to more complex oil reservoirs.

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LIST OF ACRONYMS AND ABBREVIATIONS

QRI – Quicksilver Resources Inc.;

BEG – Bureau of Economic Geology;

SCCBSU - South Central Cut Bank Sand Unit ;

NCCBSU - North Central Cut Bank Sand Unit;

NWCBSU- North West Cut Bank Sand Unit;

pu - porosity unit;

PHIA - neutron-density average porosity;

VSP – Vertical Seismic Profile;

AL - Albertoni-Lake technique;

Np - cumulative oil produced;

λ- fraction of flow in a producer attributable to flow at an injector

Measurement Units Conversion

1 barrel = 158.987295 liters;

1 ft = 0.3048 m;

1 acre= 4046.856422 m^2.

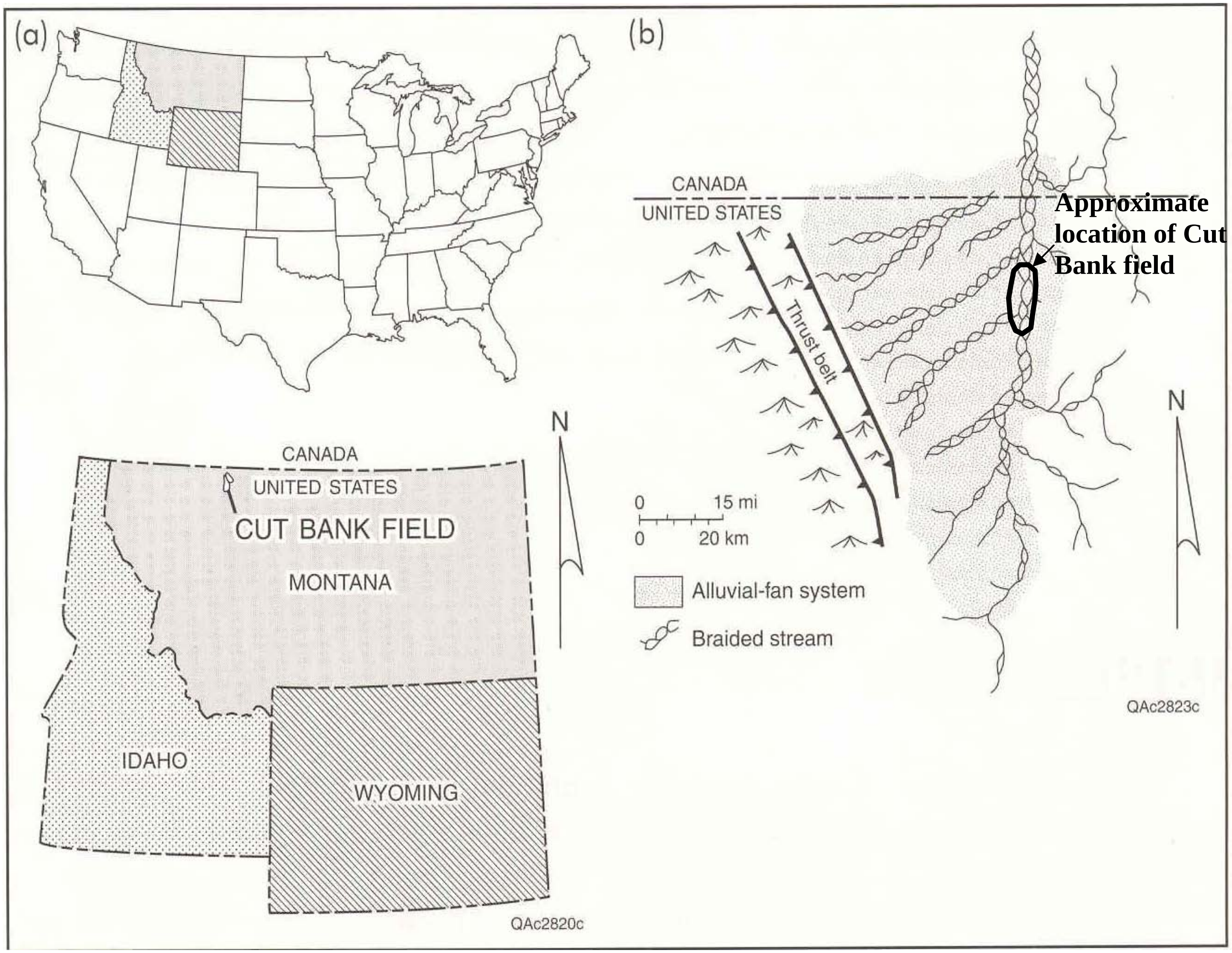


Fig 1. (a) Regional and (b) depositional settings of Cut Bank field (after J.F.Treckman, MSR Exploration, 1996).

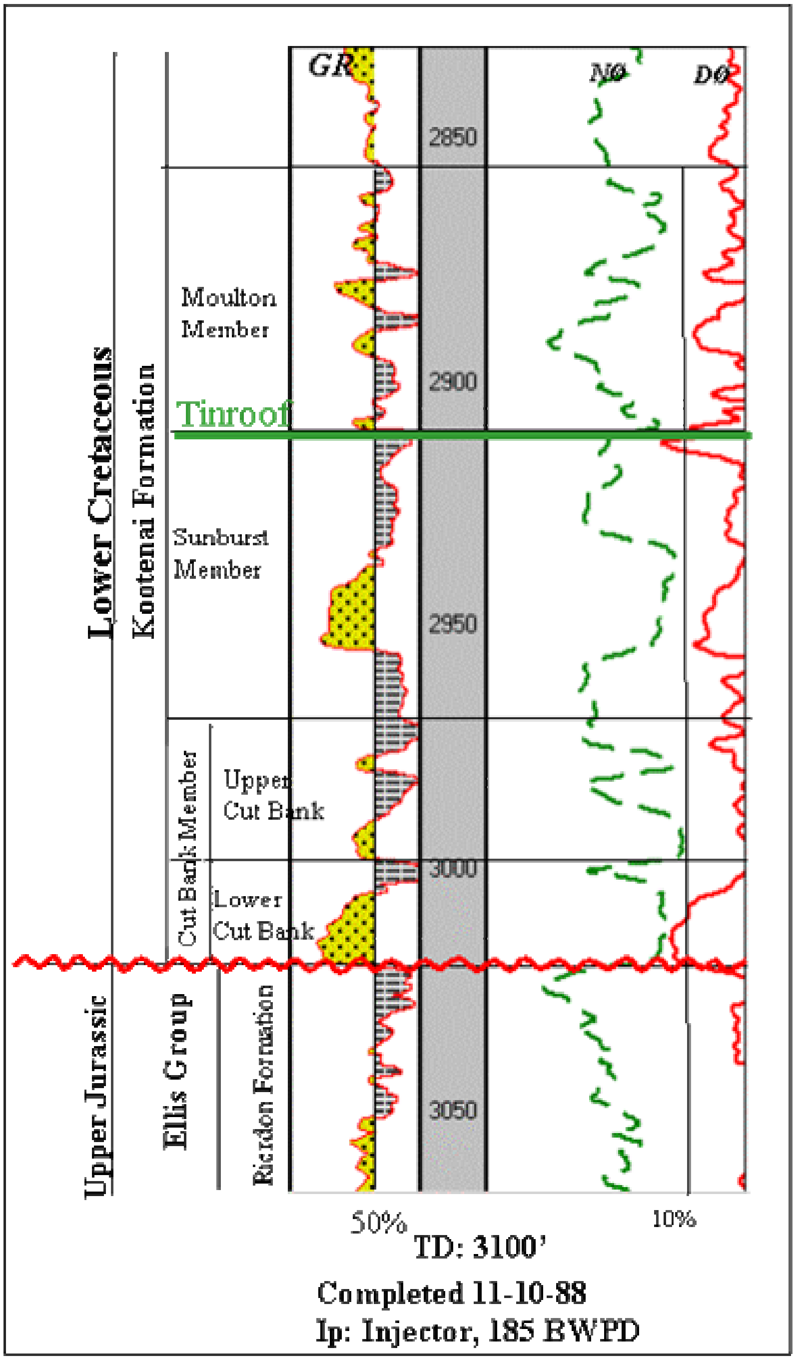


Fig. 2. Cut Bank Field – type log. Well SCCBSU 51-6.

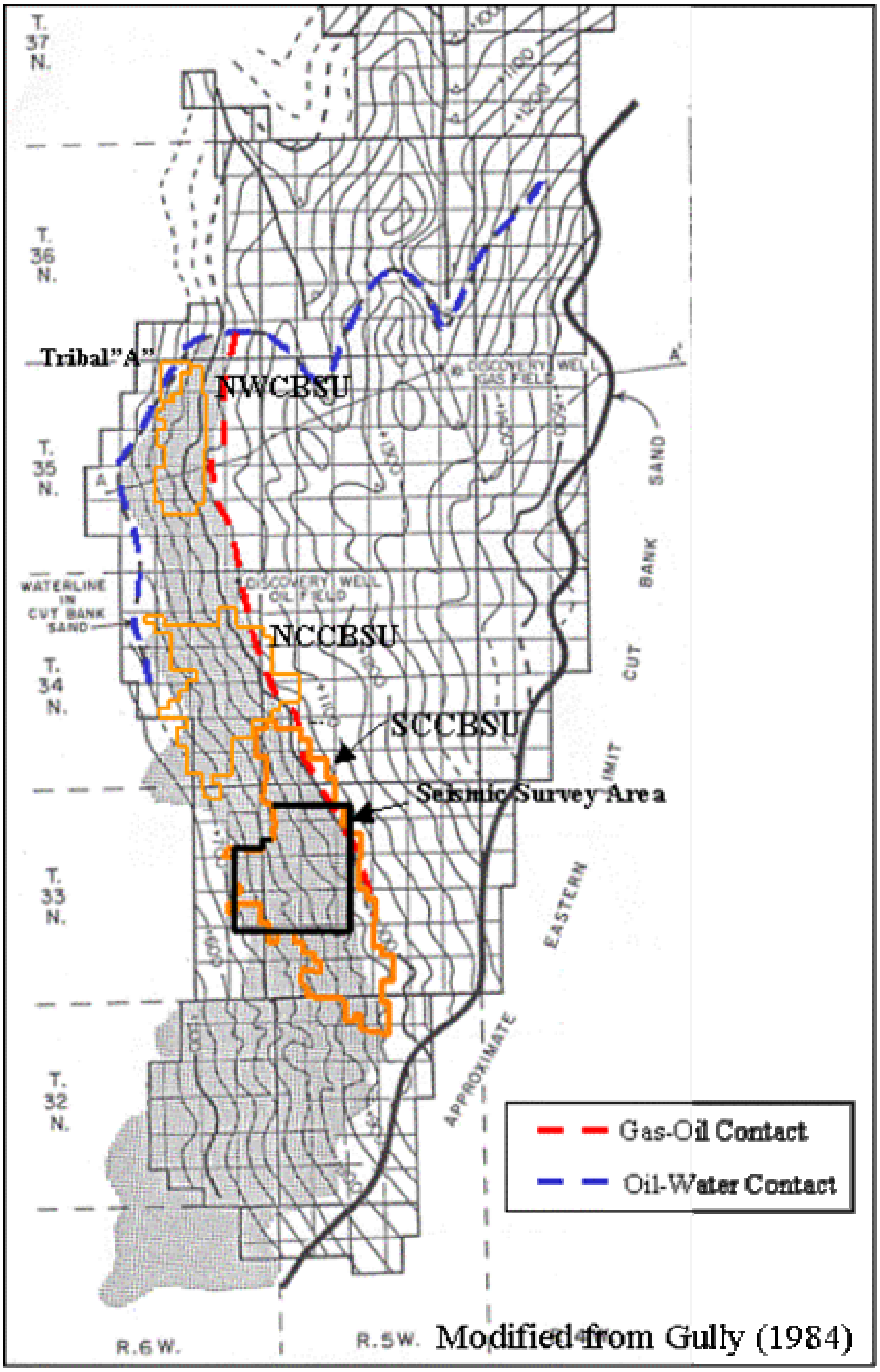


Fig. 3. Cut Bank field, generalized top of Ellis structure. Shaded area correspond to oil leg. Outlines are Cut Bank Units and 3-D seismic survey area (Modified from Gully, 1984).

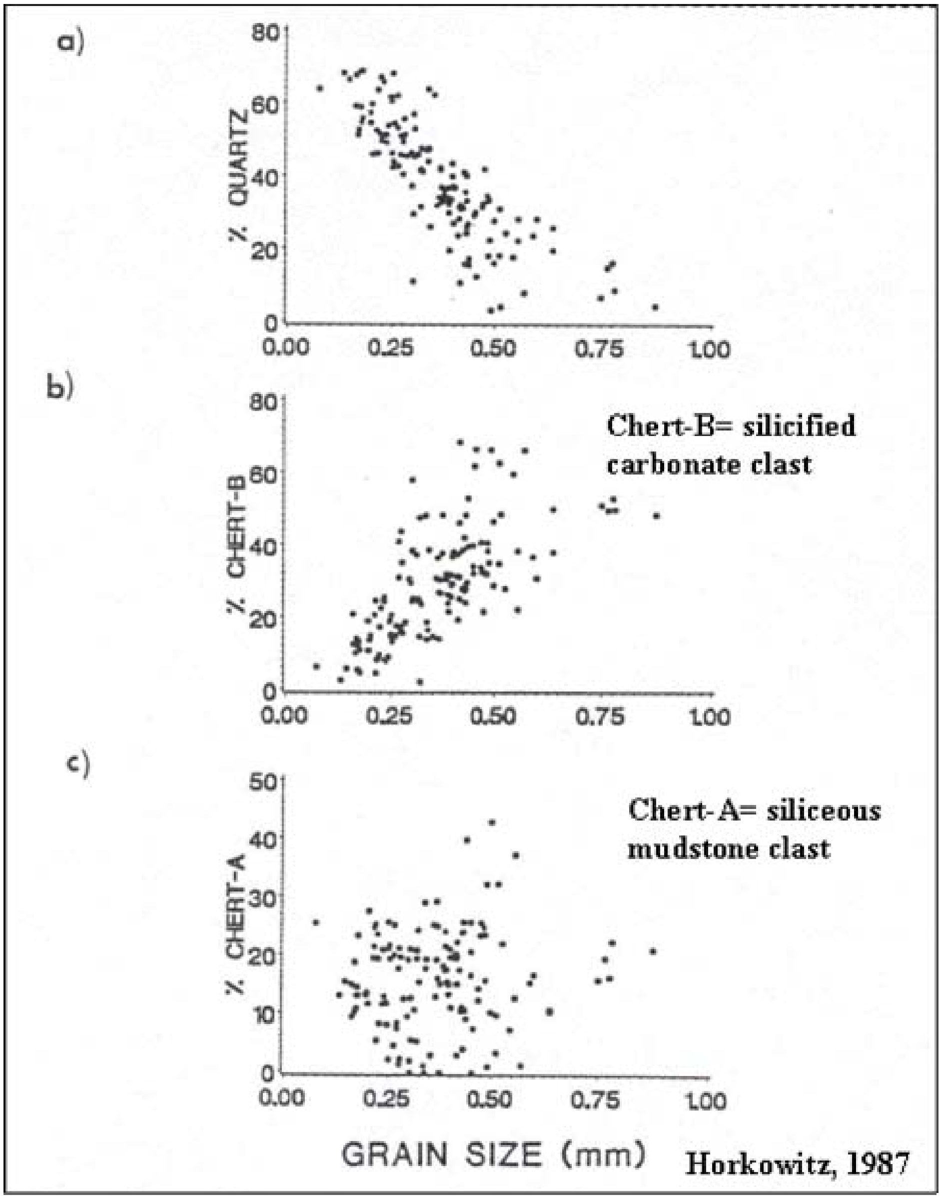


Fig 4. Relation between grain size and framework grain composition, Cut Bank field (Horkowitz, 1986).

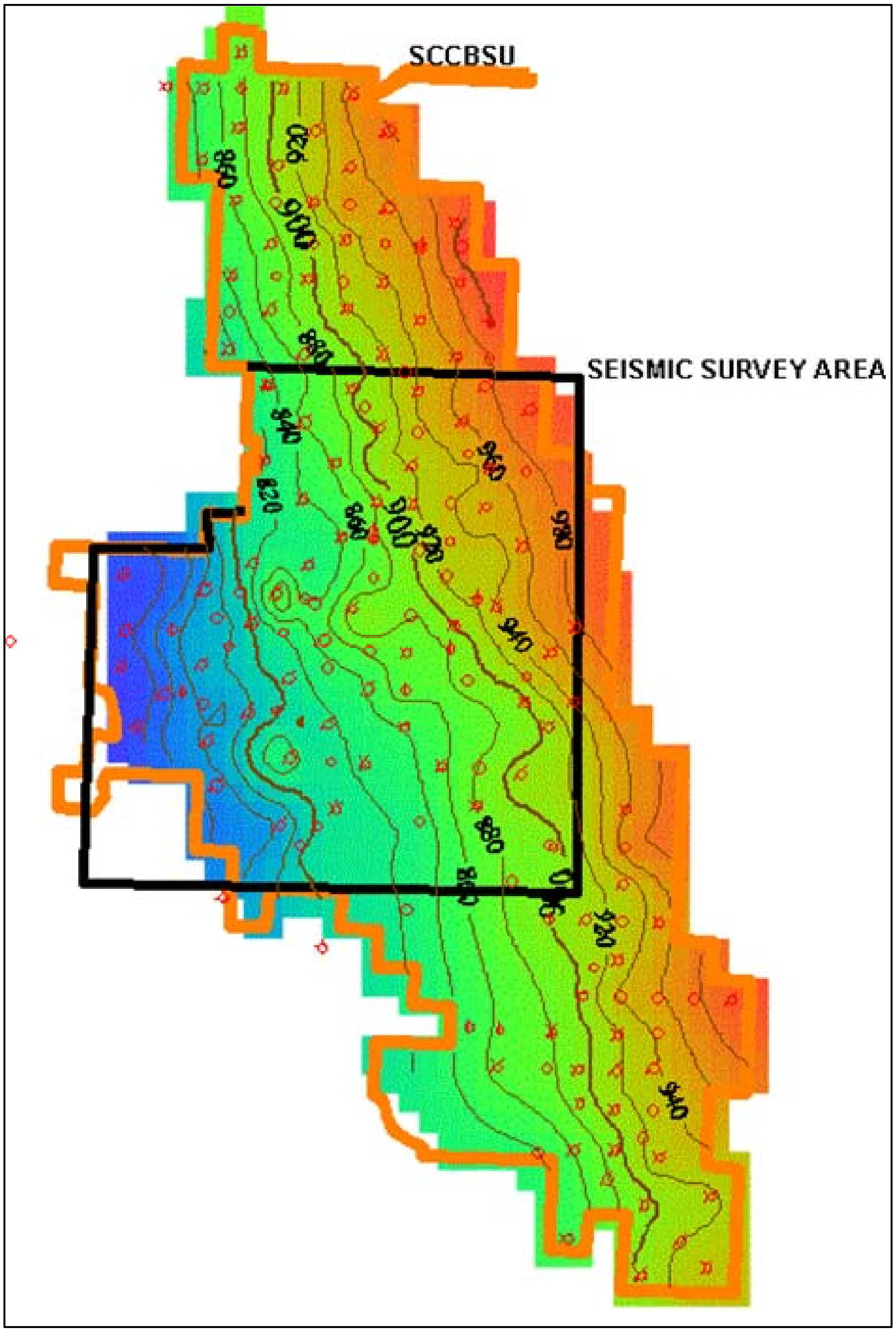


Fig. 5. SCCBSU: Structure map, top of the Ellis Group.

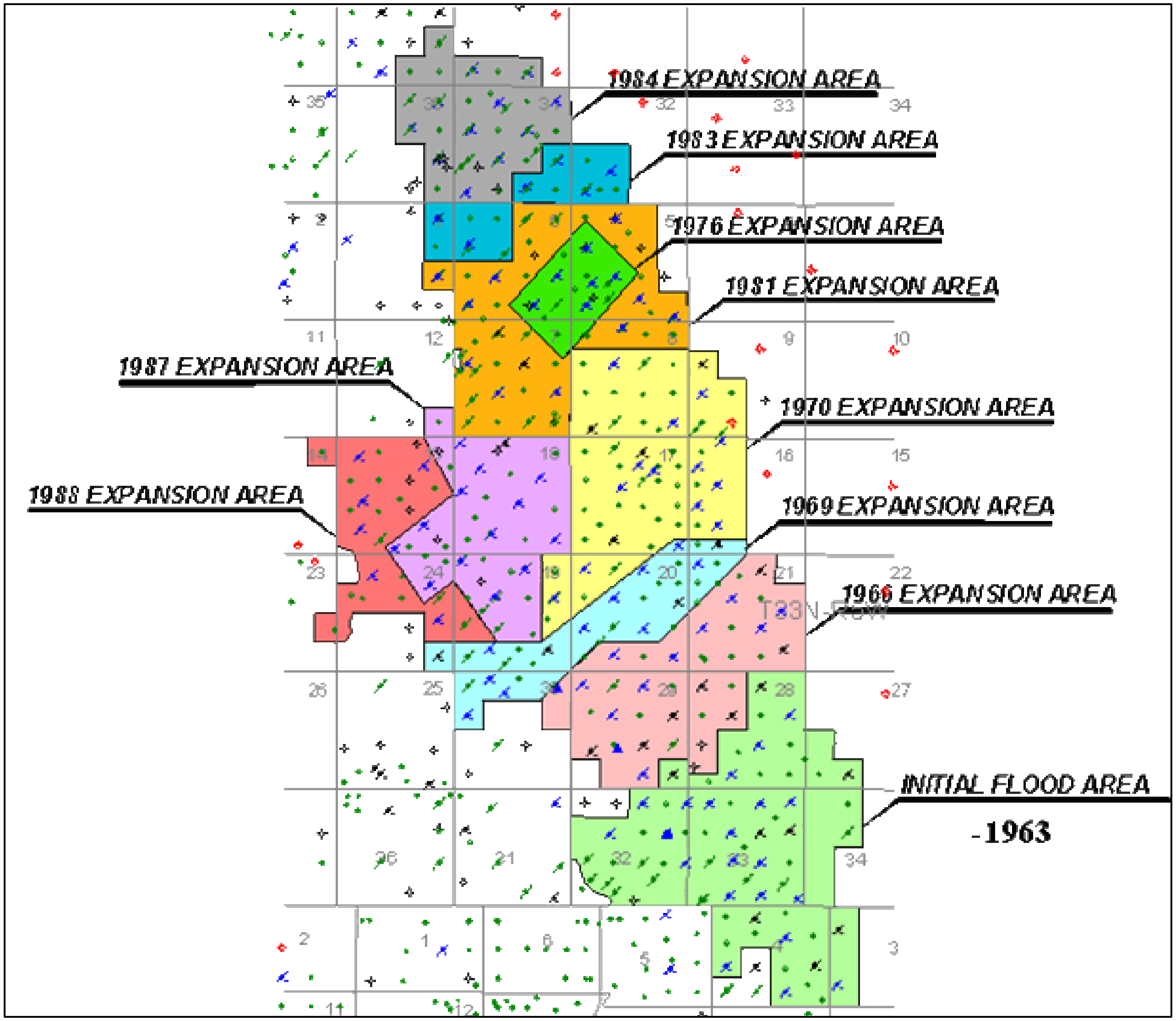


Fig. 6. SCCBSU water flood expansion history (from Quicksilver Resources, 2001).

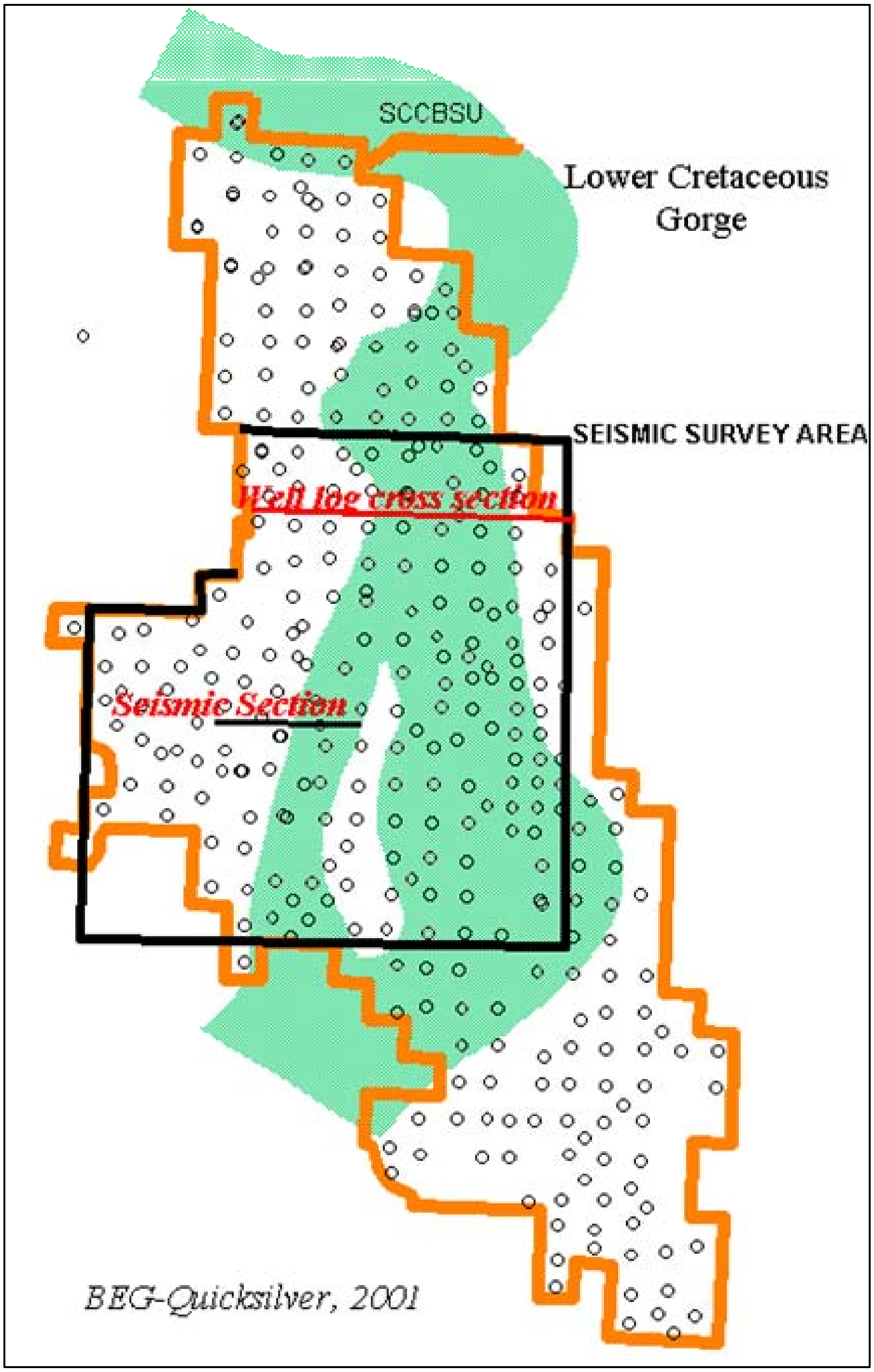


Fig. 7. South Central Cut Bank Unit. Shaded area corresponds to Lower Cretaceous Gorge where the "Tinroof" is absent (from BEG-Quicksilver Resources, 2001).

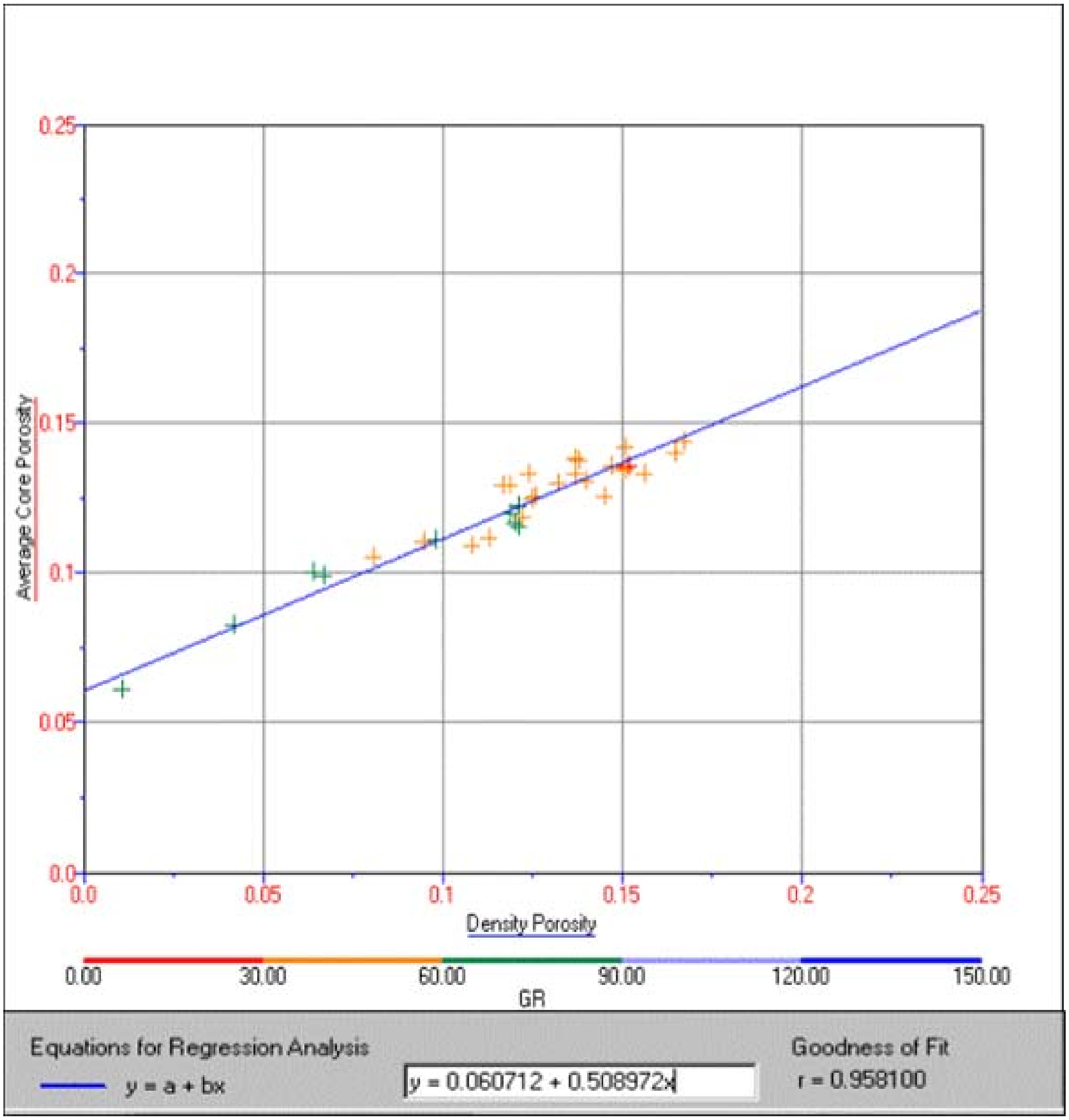


Fig. 8. Well 37-7 - Core-well log porosity calibration for Lower Cut Bank Sand.

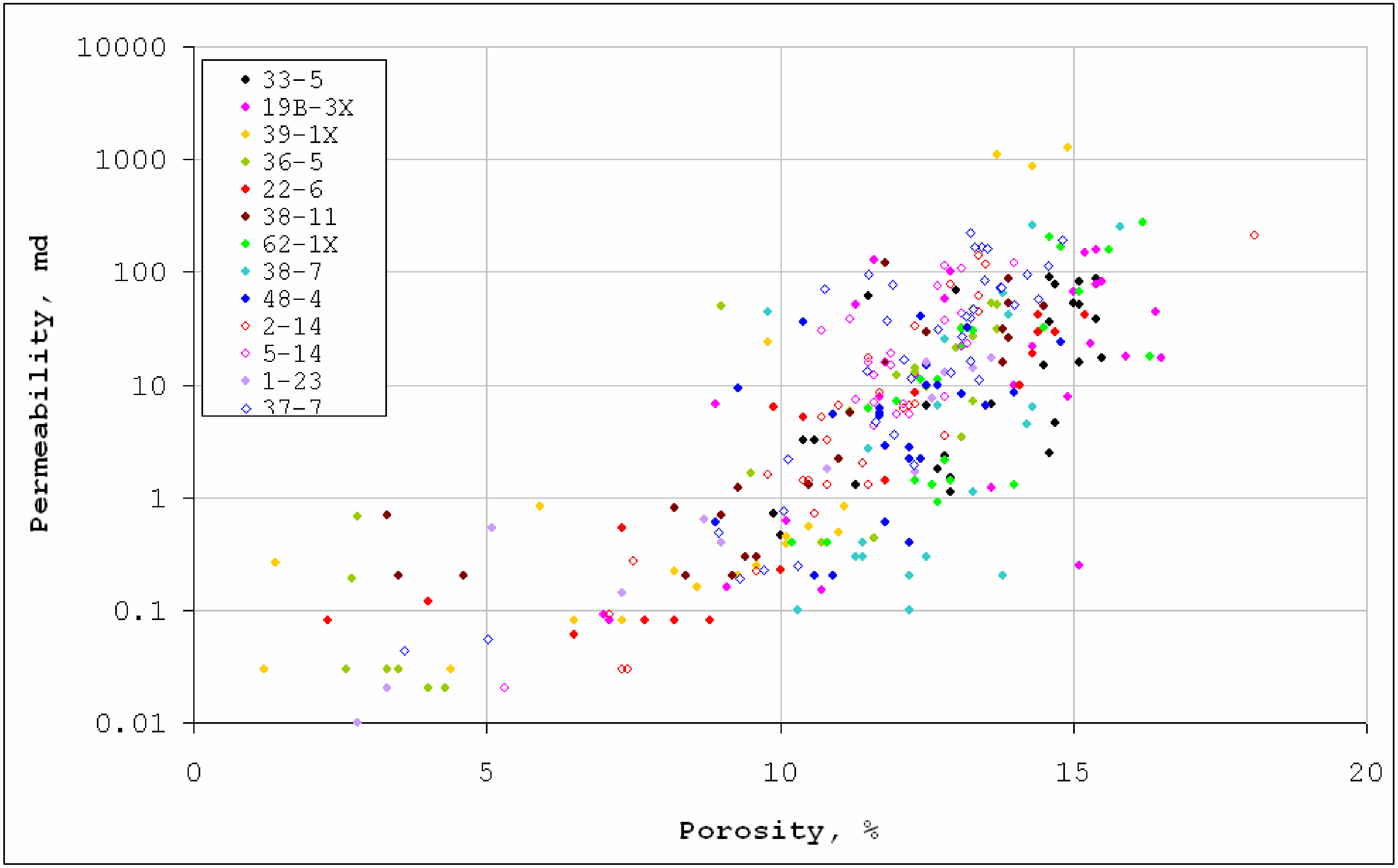


Fig. 9. Core porosity-permeability crossplot .

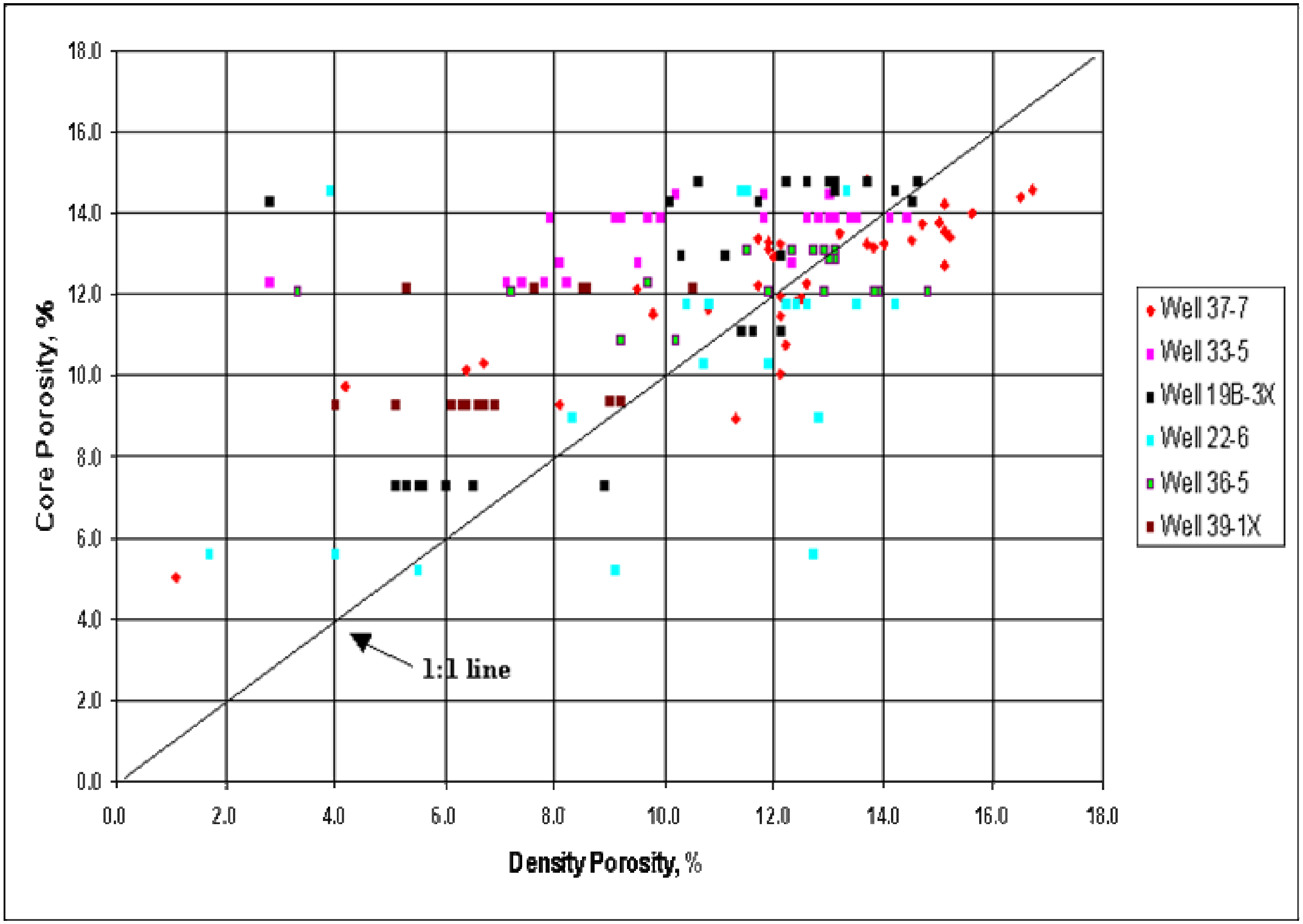


Fig. 10. Core vs. density porosity comparison for all cored wells in the Cut Bank Sand.

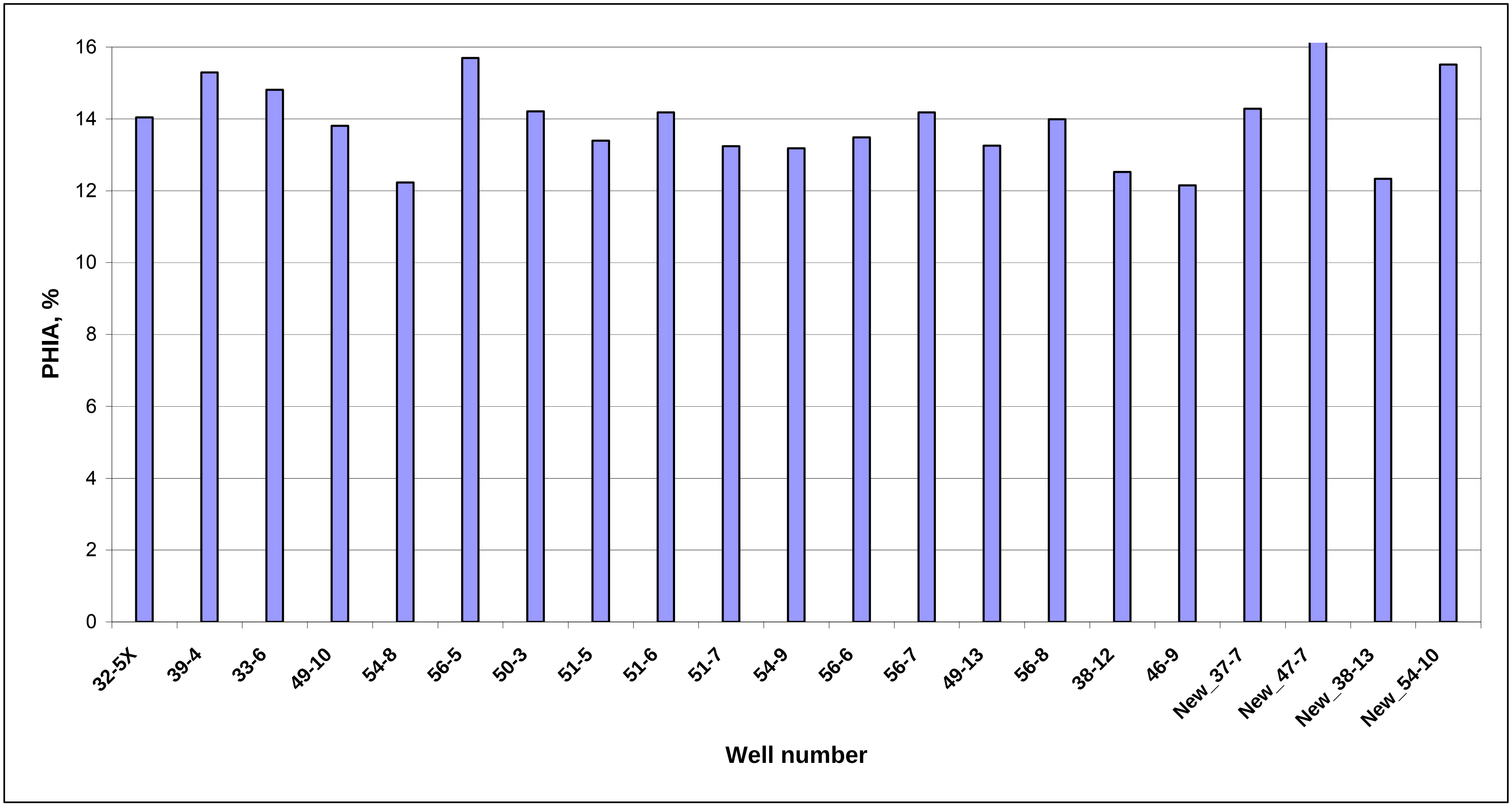


Fig. 11. Neutron-density average porosity values for net pay in the Lower Cut Bank Sand. Net pay is based on a 10% porosity cutoff.

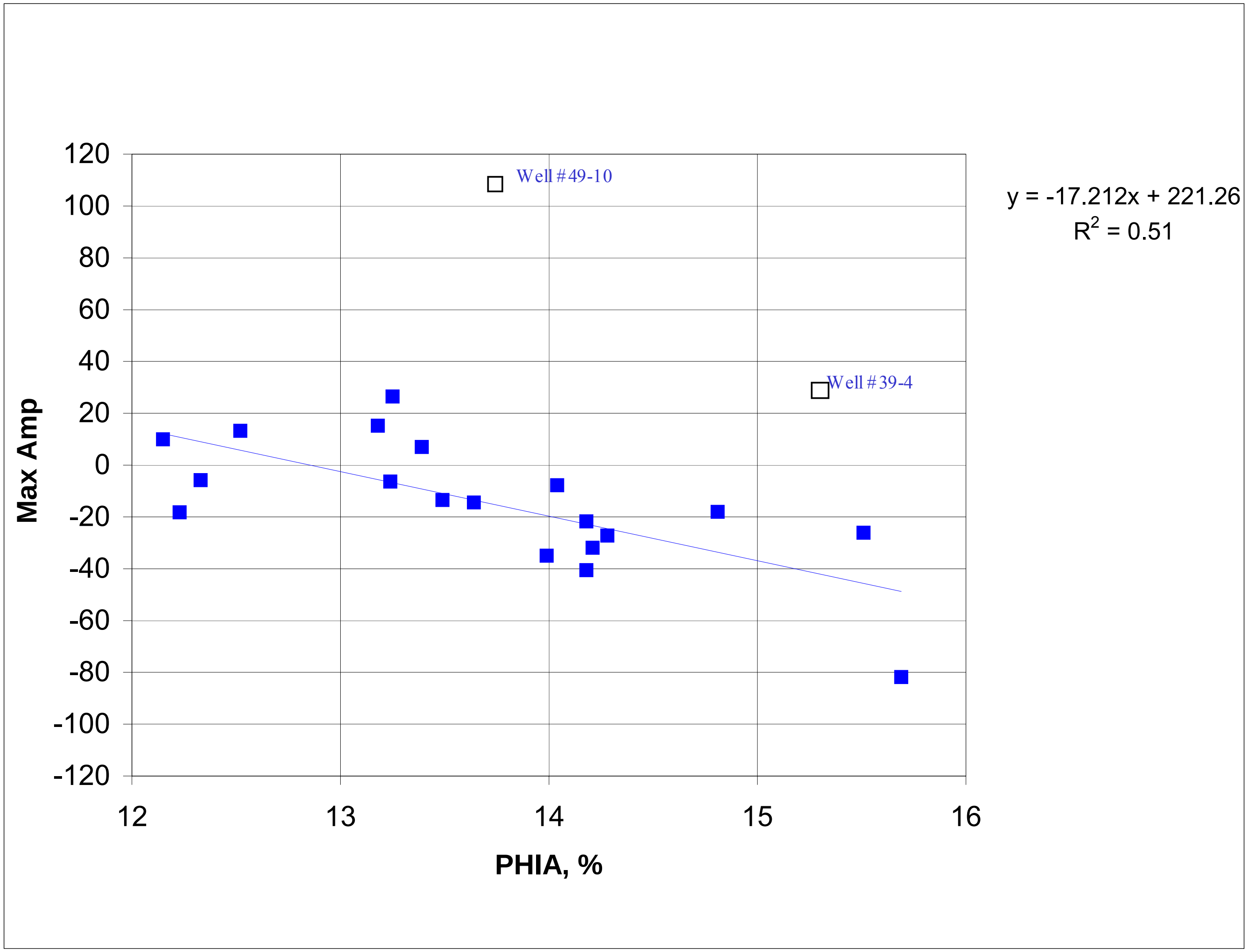


Fig. 12 . Relation between the log neutron-density average porosity and 3-D seismic amplitude at the well ties. Each point represent a well with a given single character name. The empty squares are the excluded wells.

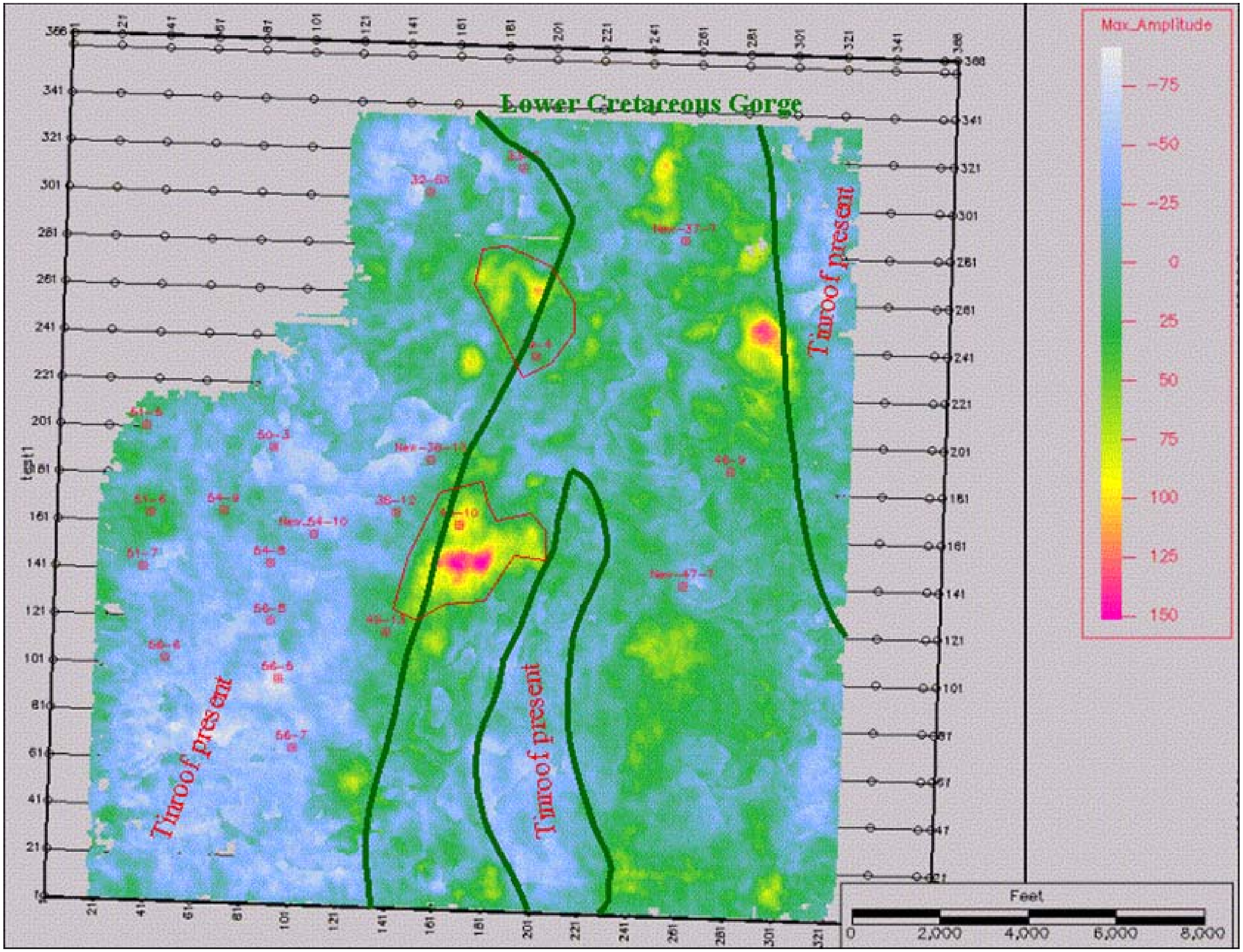


Fig. 13. Maximum amplitude of Lower Cut Bank horizon. Red is highest amplitude and blue is lowest. Red polygons are areas of mismatch.

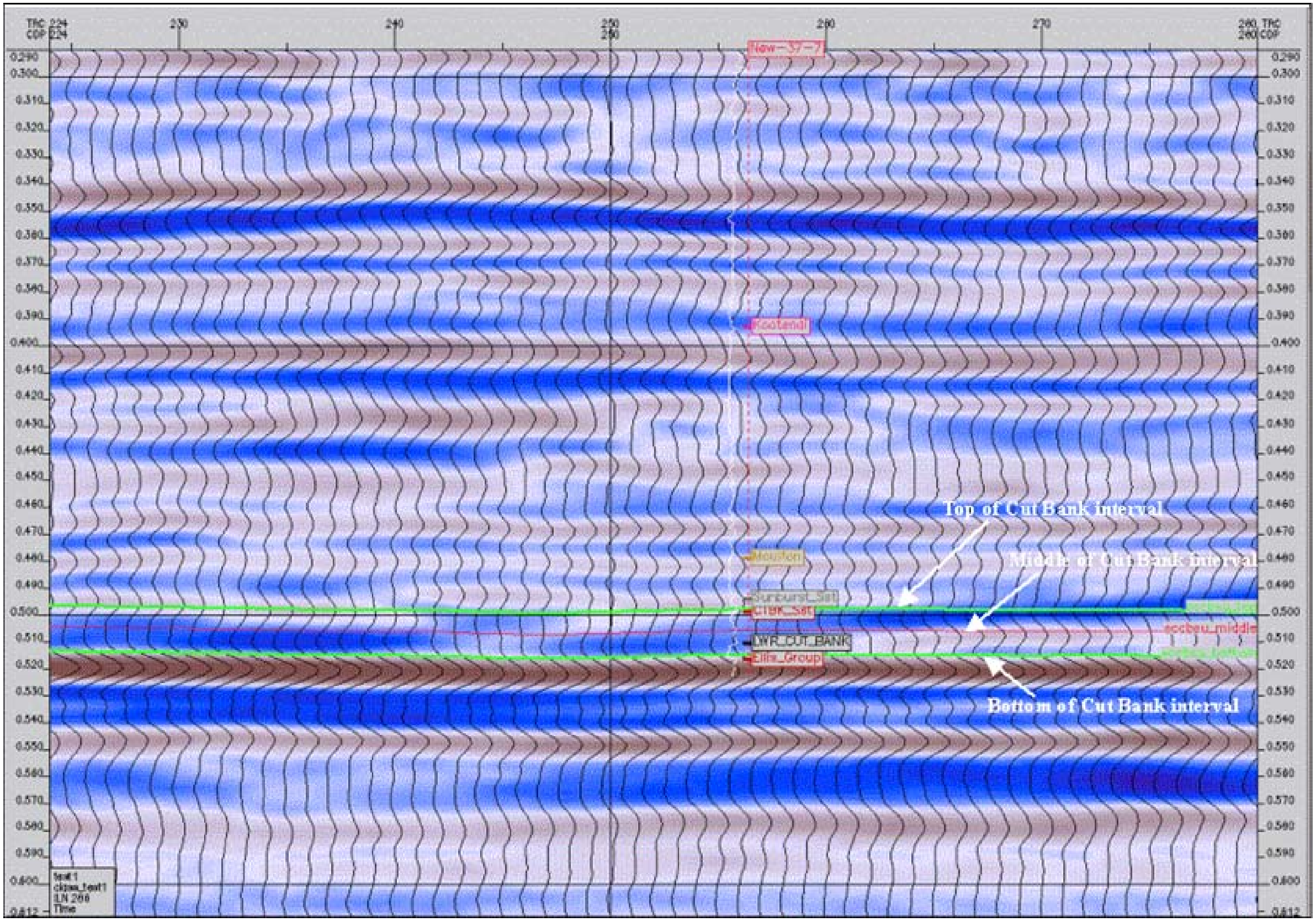


Fig. 14. Seismic section along inline 286 displaying upper, middle , and lower bounding stratal surfaces. Notice the bottom of Lower Cut Bank interval, or top of Ellis, is at the zero crossing above the positive amplitudes.

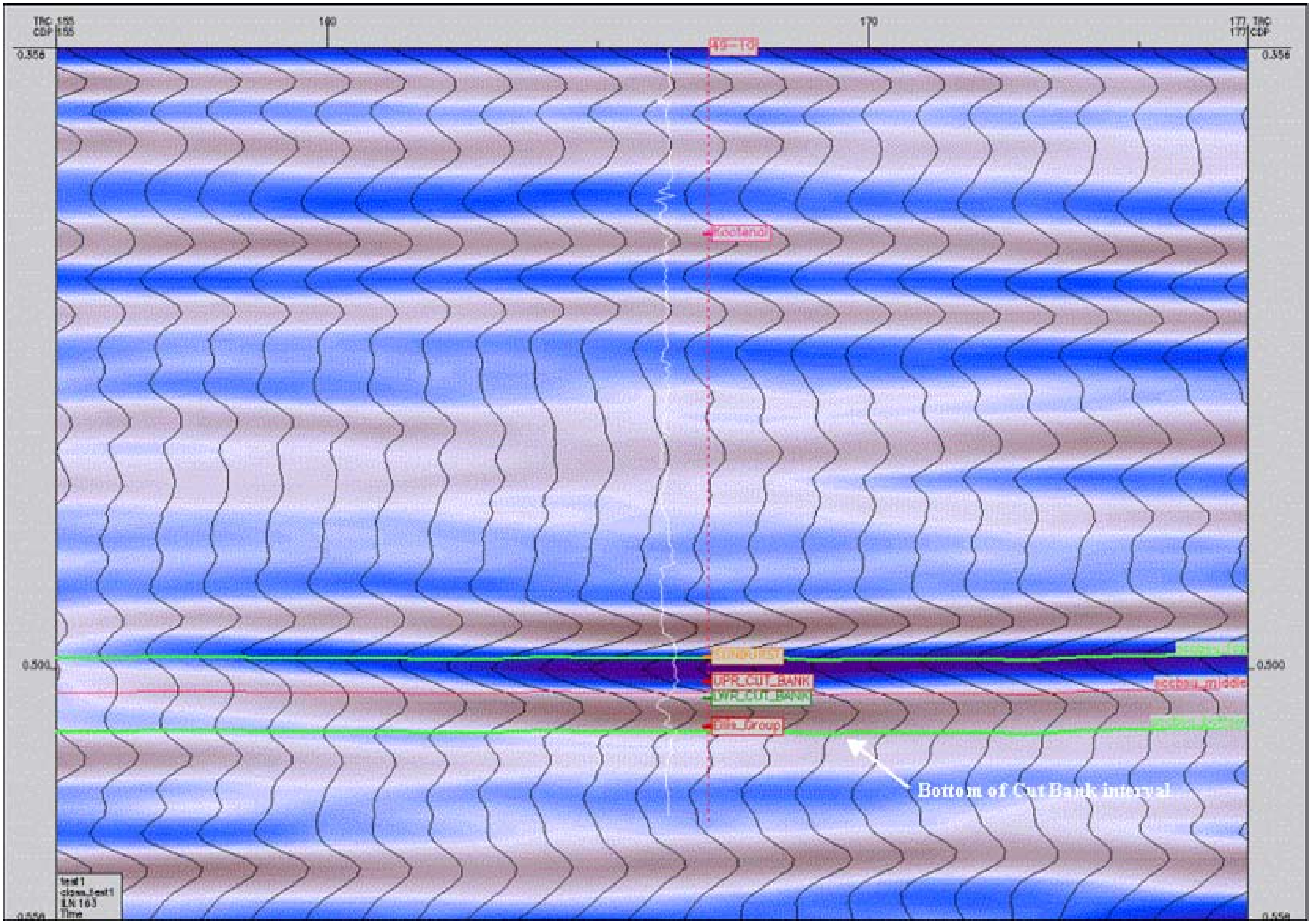


Fig. 15. Seismic section along inline 163 displaying upper, middle , and lower bounding stratal surfaces. Maximum amplitude at Well 49-10 is anomalously high compared to the average log porosity value. One reason for that may be inconsistency of interpretation of the bottom of the Lower Cut Bank strata (Ellis top) in this area. This surface is at the zero crossing above the positive amplitudes all over the seismic survey (see Figure 14) except the area of problem.

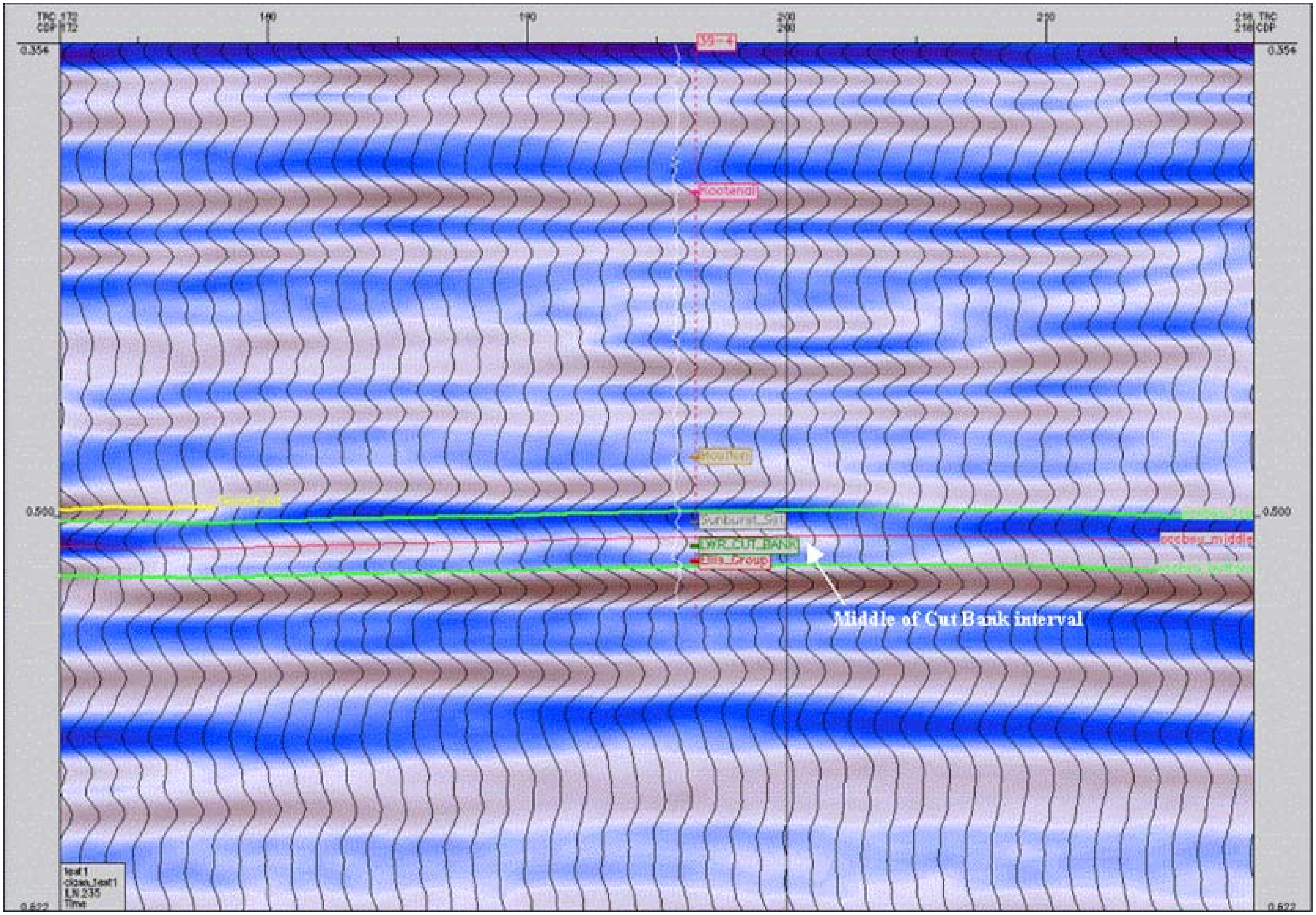


Fig. 16. Seismic section along inline 235 displaying upper, middle , and lower bounding stratal surfaces. In Well 39-4 the maximum amplitude value under-predicts the porosity. One of the reason may be inconsistency of interpretation of Lower Cut Bank interval in well log and seismic intepretation. Middle of Cut Bank interval in seismic does not correspond to the top of Lower Cut Bank interval.

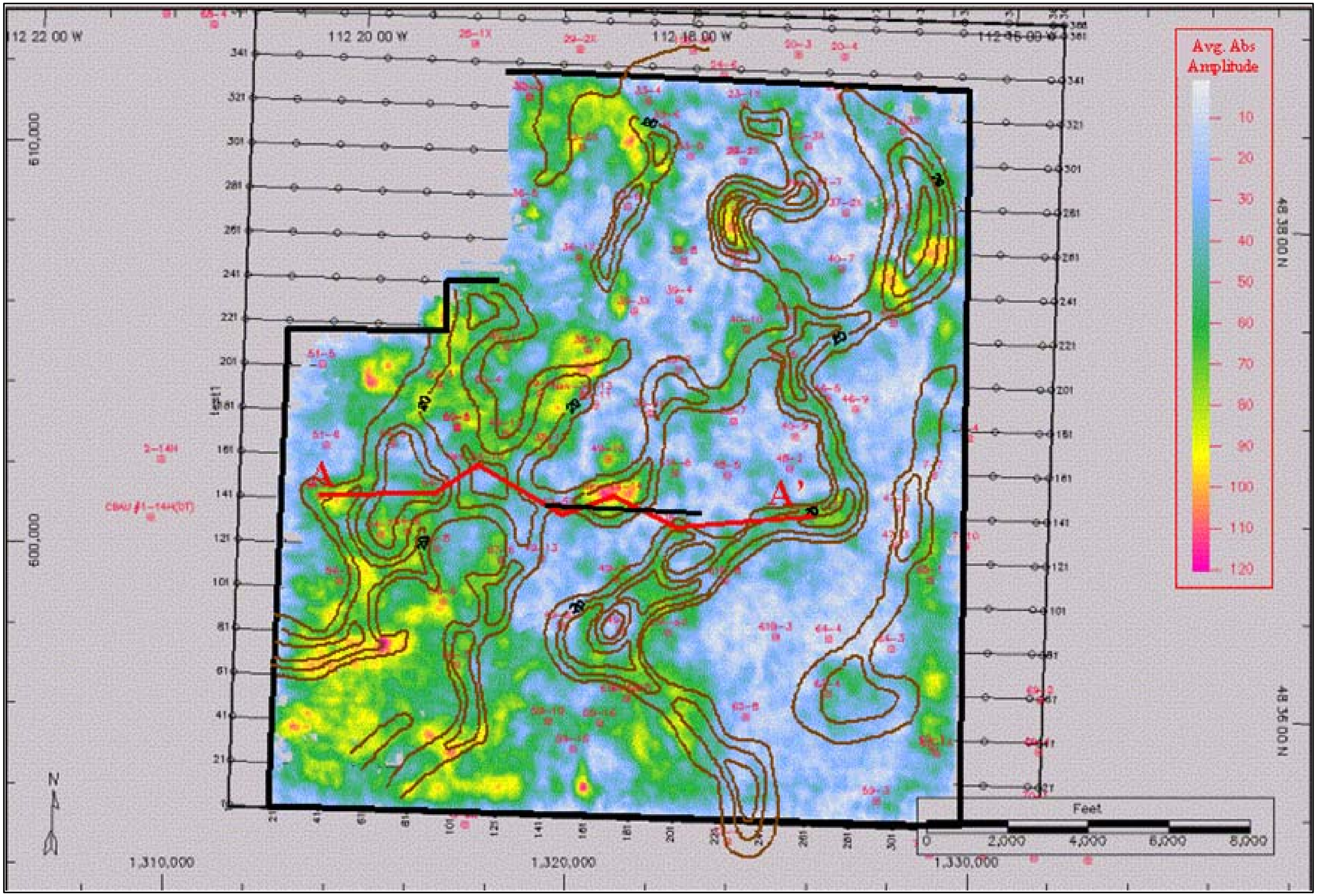


Fig. 17. QRI/BEG net sand thickness contours >15 ft superposed on the average absolute seismic amplitude map. Generally, higher average absolute amplitude corresponds to greater net sand thickness.

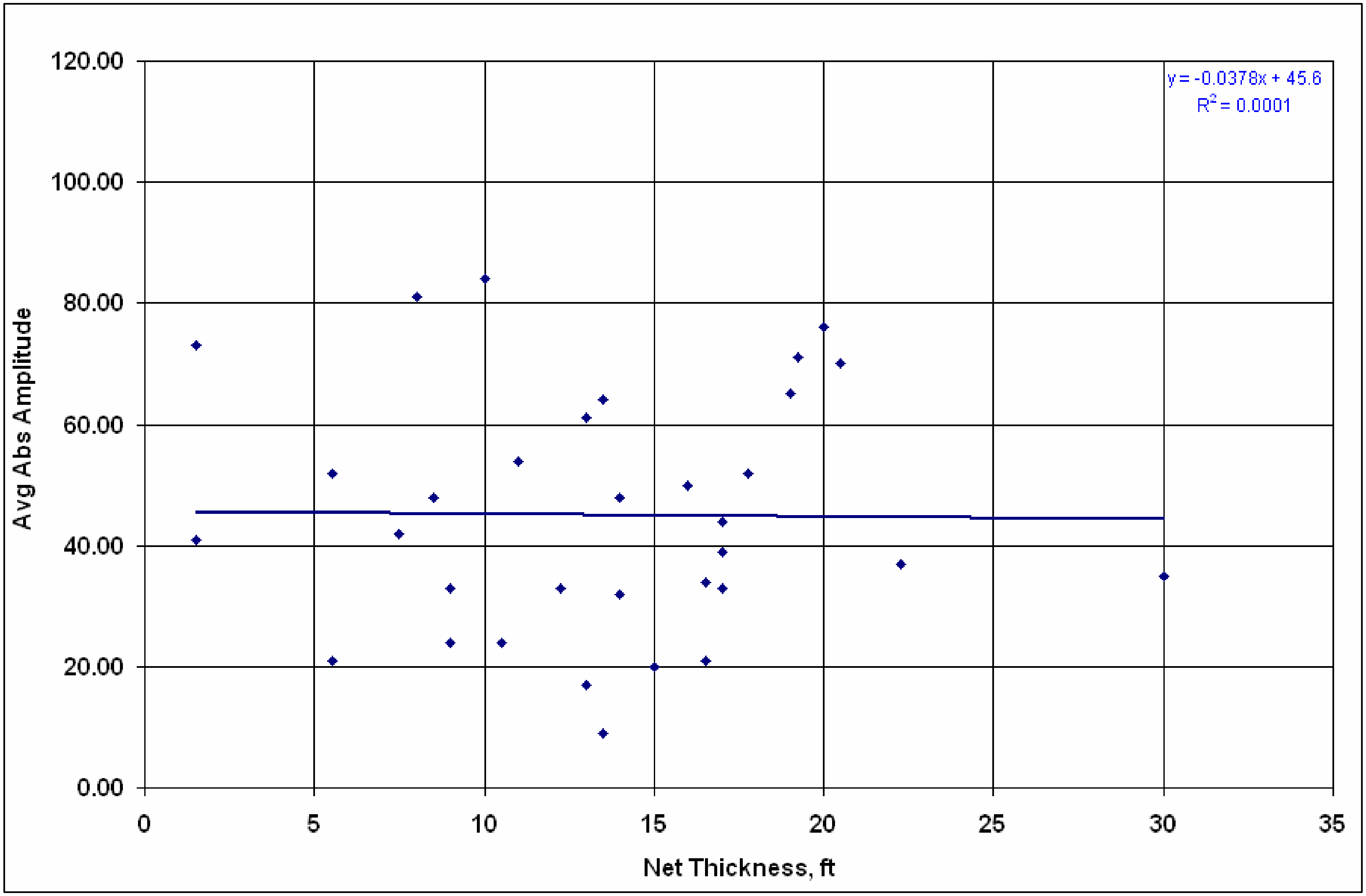


Fig.18 . There is no correlation between net sand thicknesses from well logs (based on 60% GR and 10% porosity cutoff) and average absolute seismic amplitude.

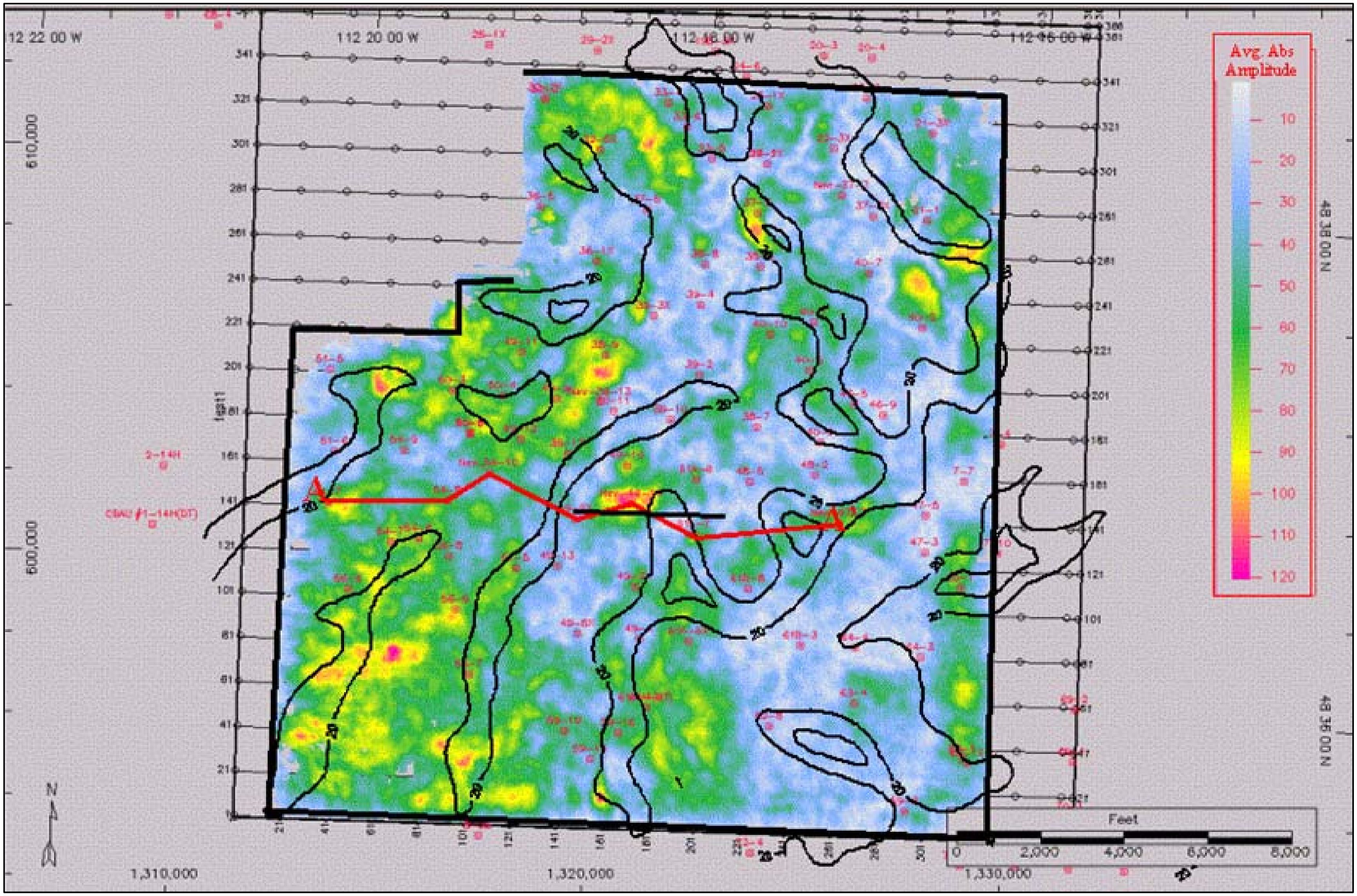


Fig. 19. UNOCAL net sand thickness contours (20 ft and greater thickness) superposed on the average absolute seismic amplitude map.

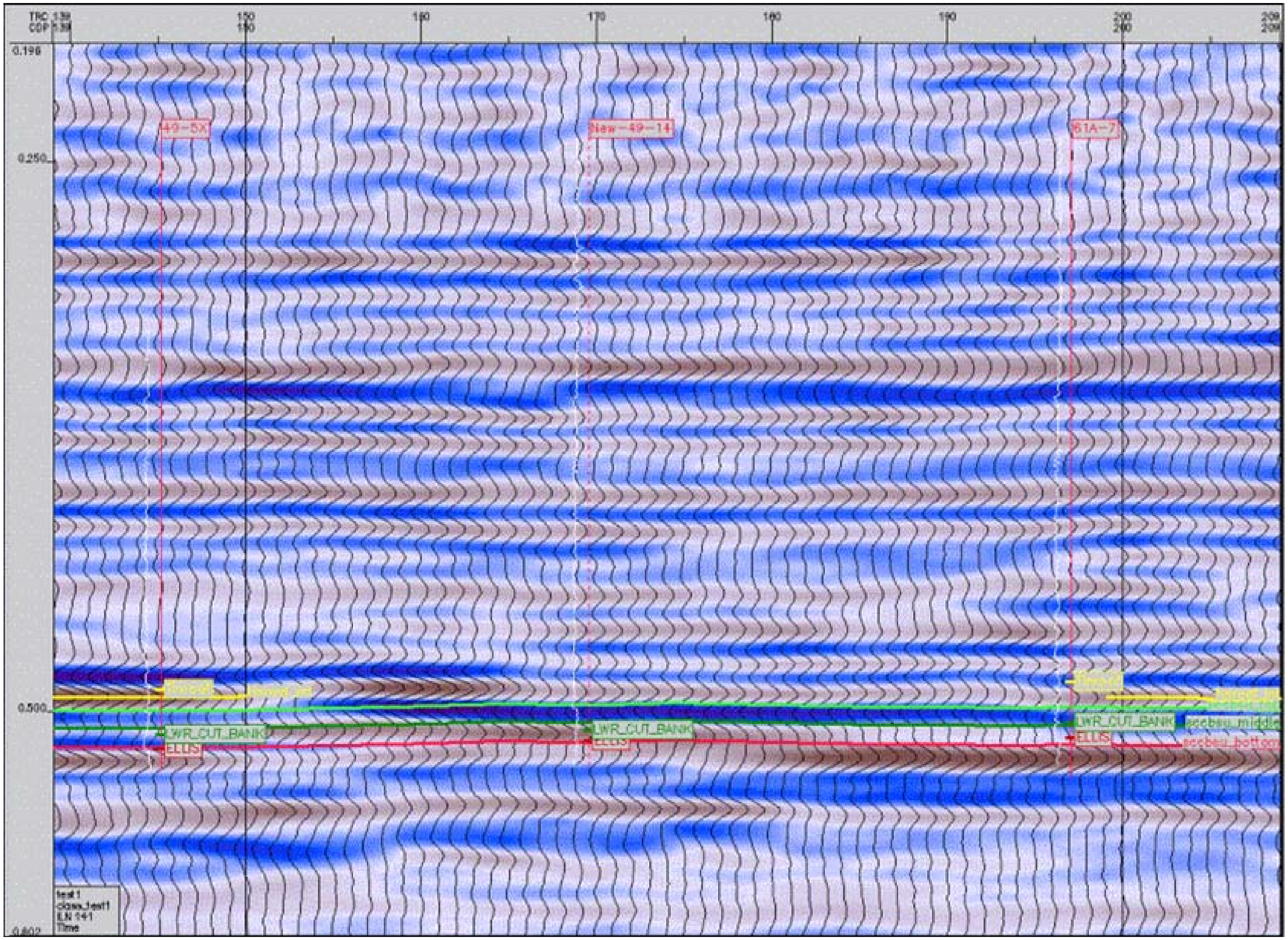


Fig. 20. West to east seismic cross-section (along inline 141) through the SCCBSU 49-14 well. Red marker is base of Cut Bank or top of Ellis; dark and light green markers are top of lower Cut Bank and top of upper Cut Bank, respectively. Location of this cross section is shown as black line in Figures 17 and 19.

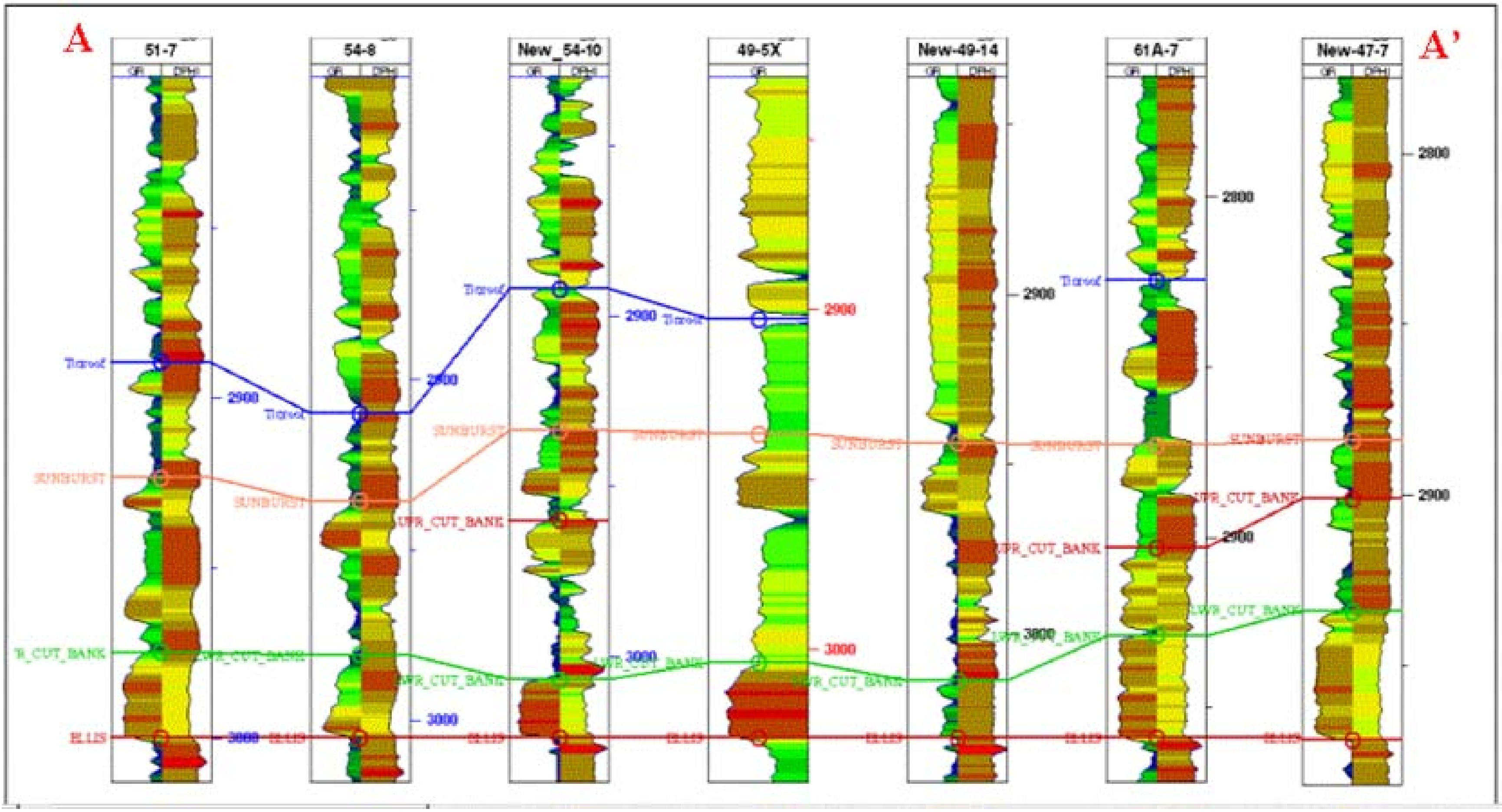


Fig. 21. East to west cross-section through the SCCBSU 49-14 well . GR scale increases from 0 to 150 API from left to right; DPHI – density porosity increases from –0.15 to 0.45 from right to left. Location of this cross section is shown as red line in figures 17 and 19.

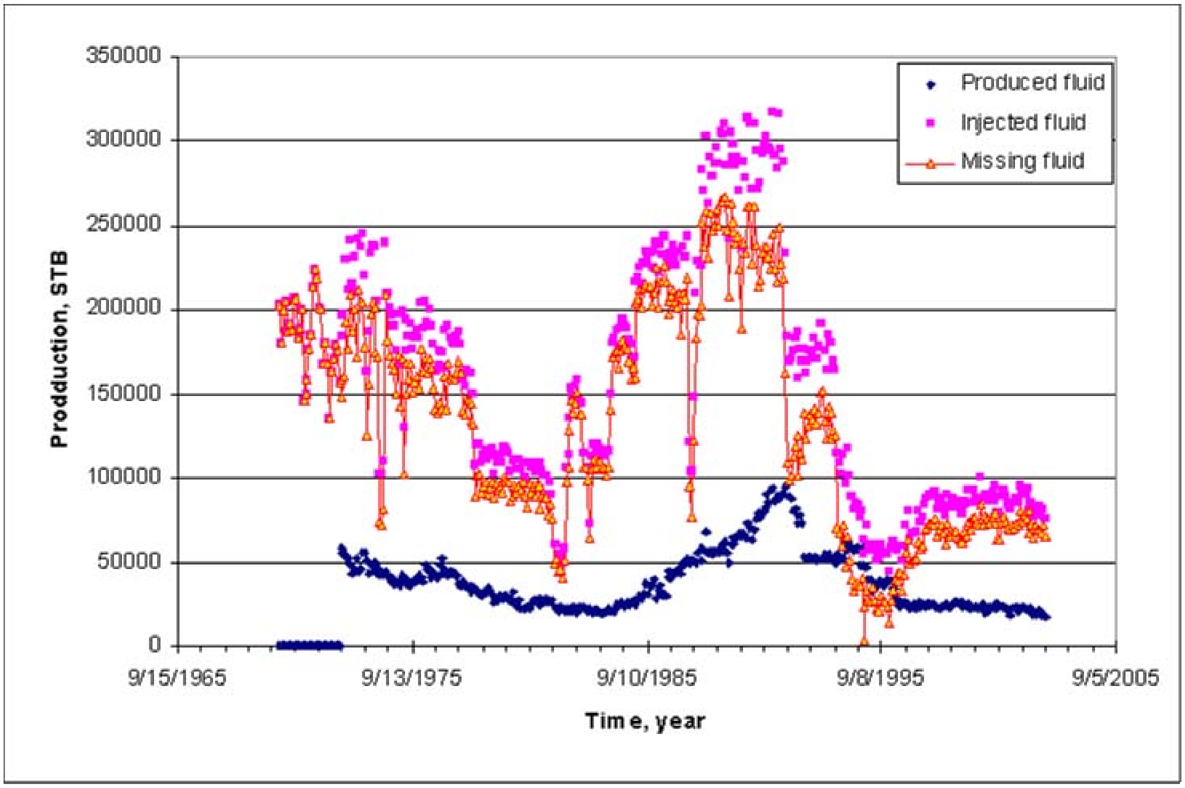


Fig. 22. History of produced fluid, injected fluid and missing fluid. Most of the injected fluid is missing in the formation of SCCBSU.

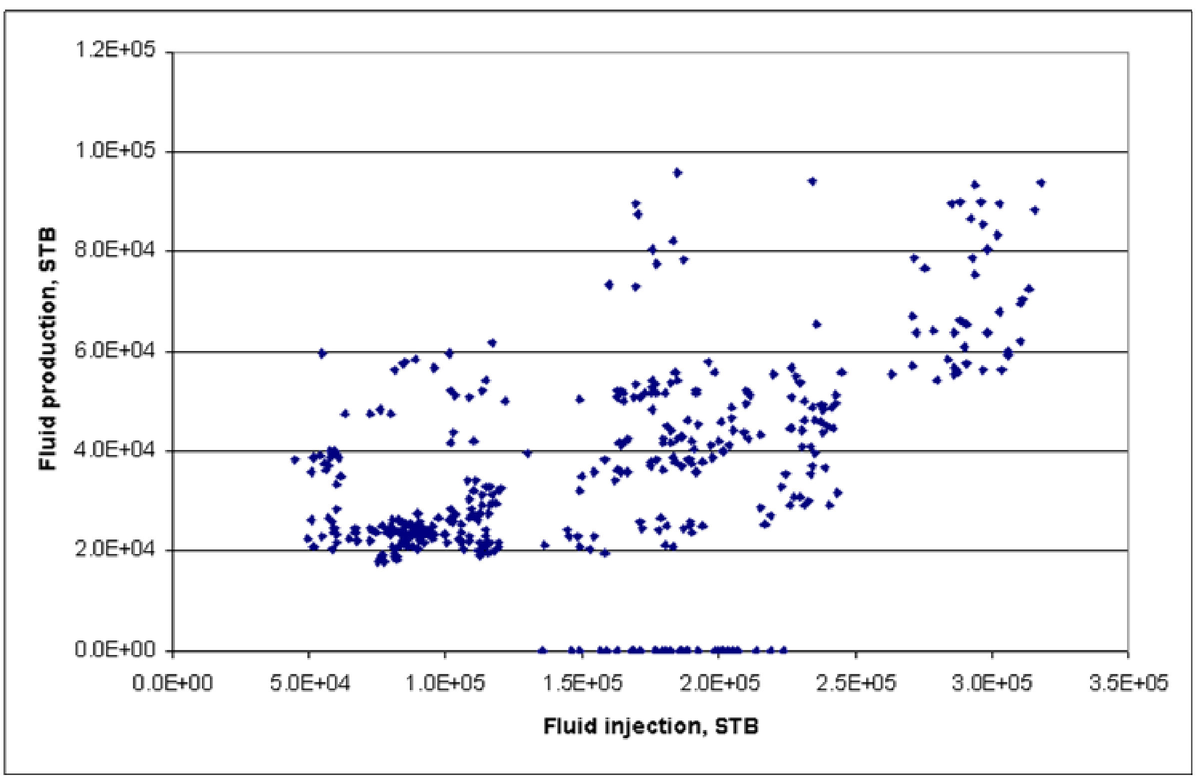


Fig. 23. Correlation between fluid injection and fluid production is not good.

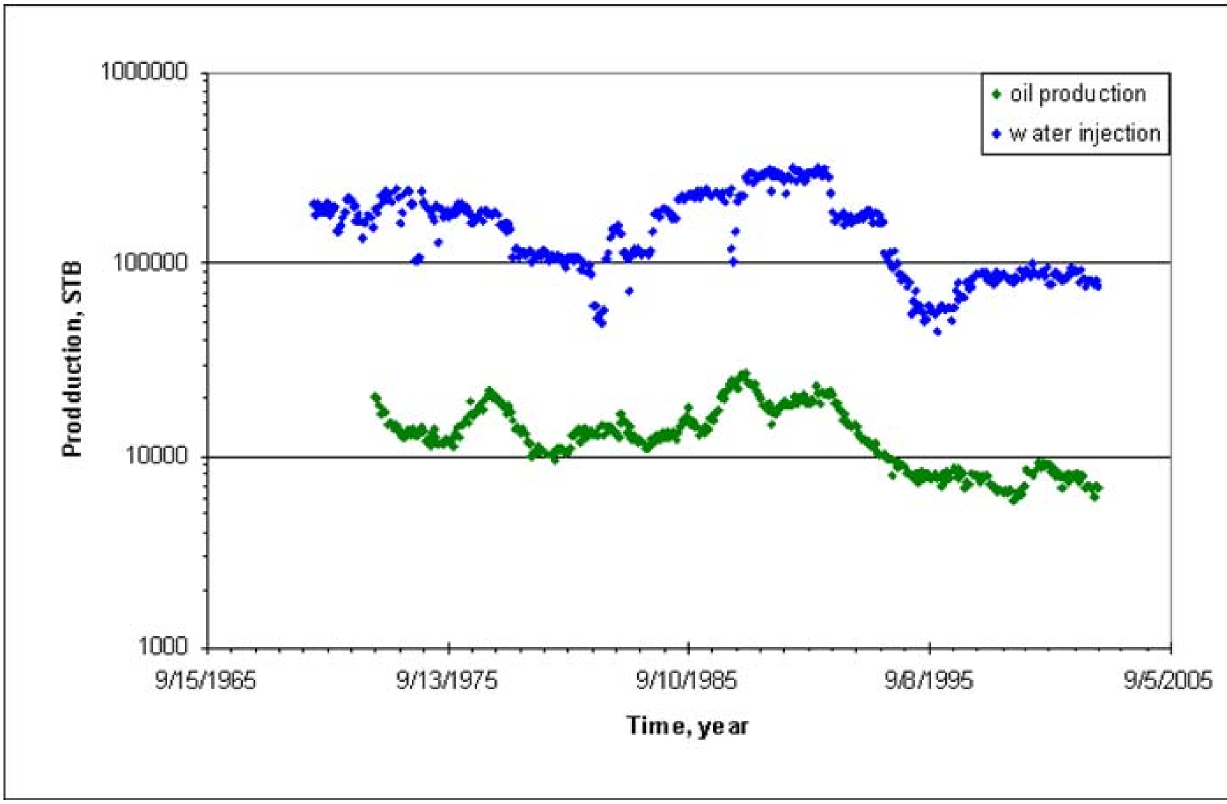


Fig. 24. SCCBSU production and injection history from year 1968 to 2002. The increase in water injection does not increase the oil production very much for the whole SCCBSU

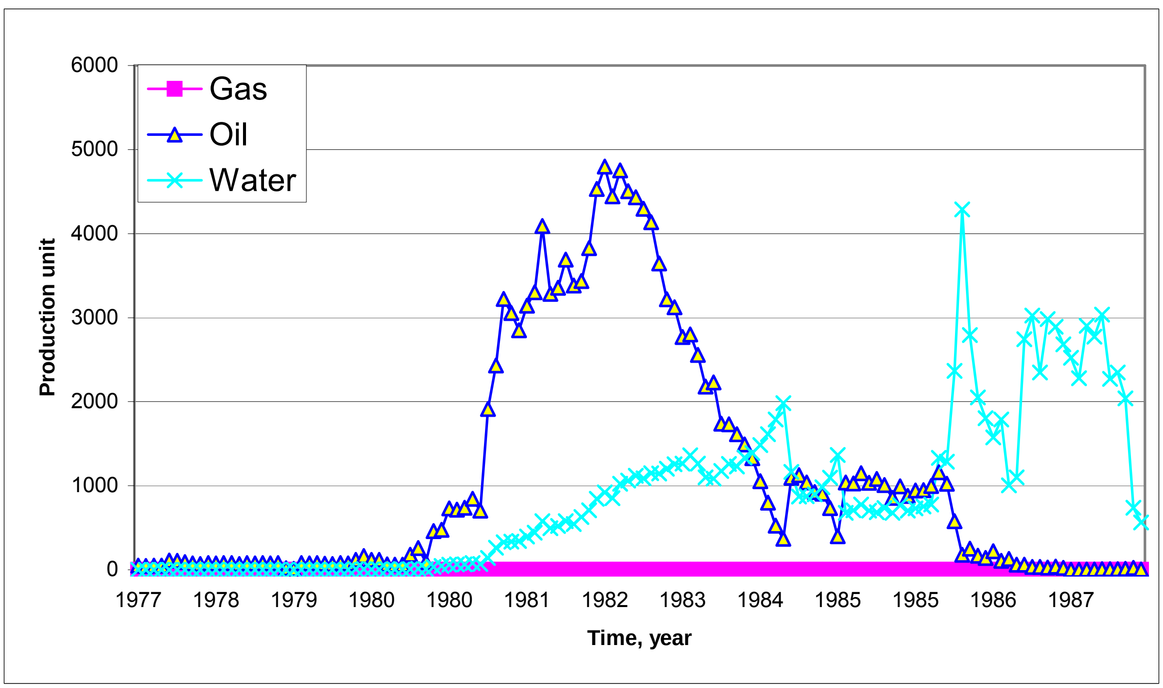


Fig. 25. Production history of well API 2503505004, showing response to water injection.

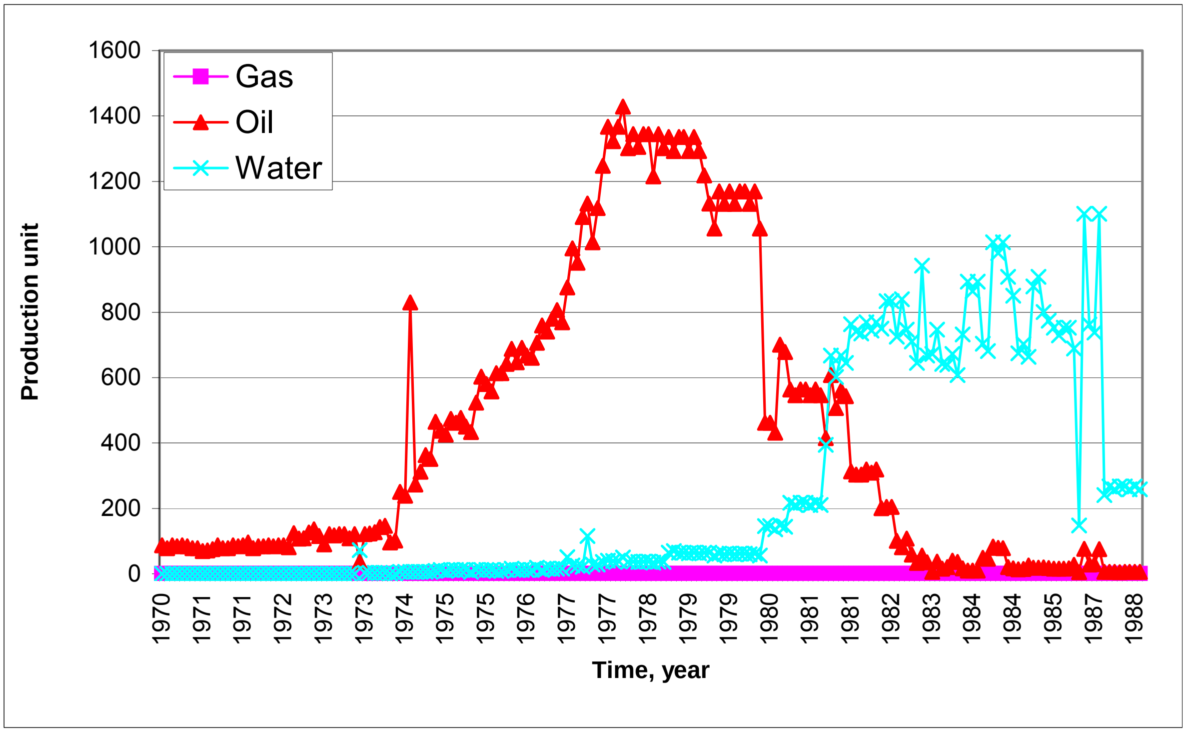


Fig. 26. Production history of well API 2503505637, showing response to water injection.

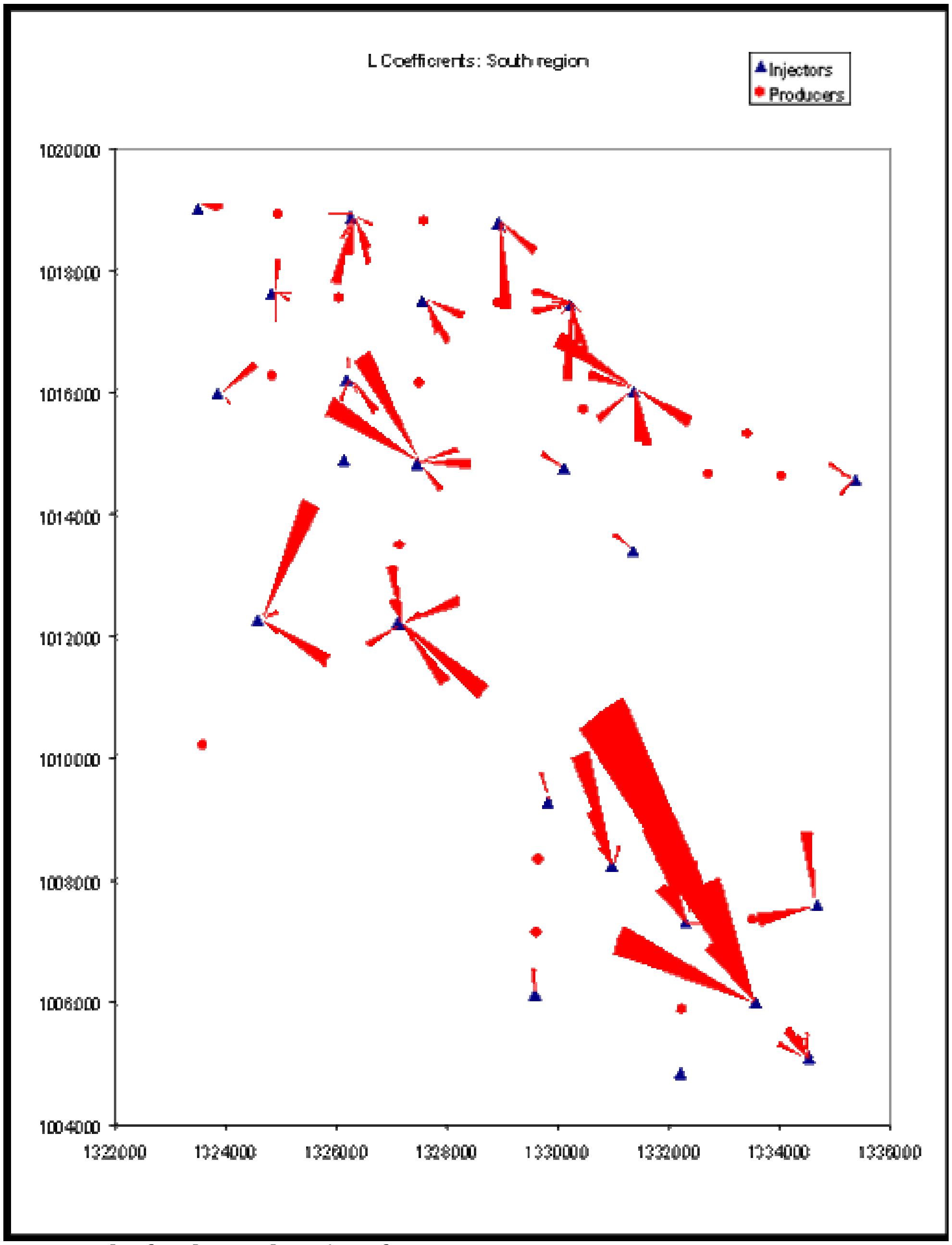


Fig. 27. Arrow plot for the south region of SCCBSU.

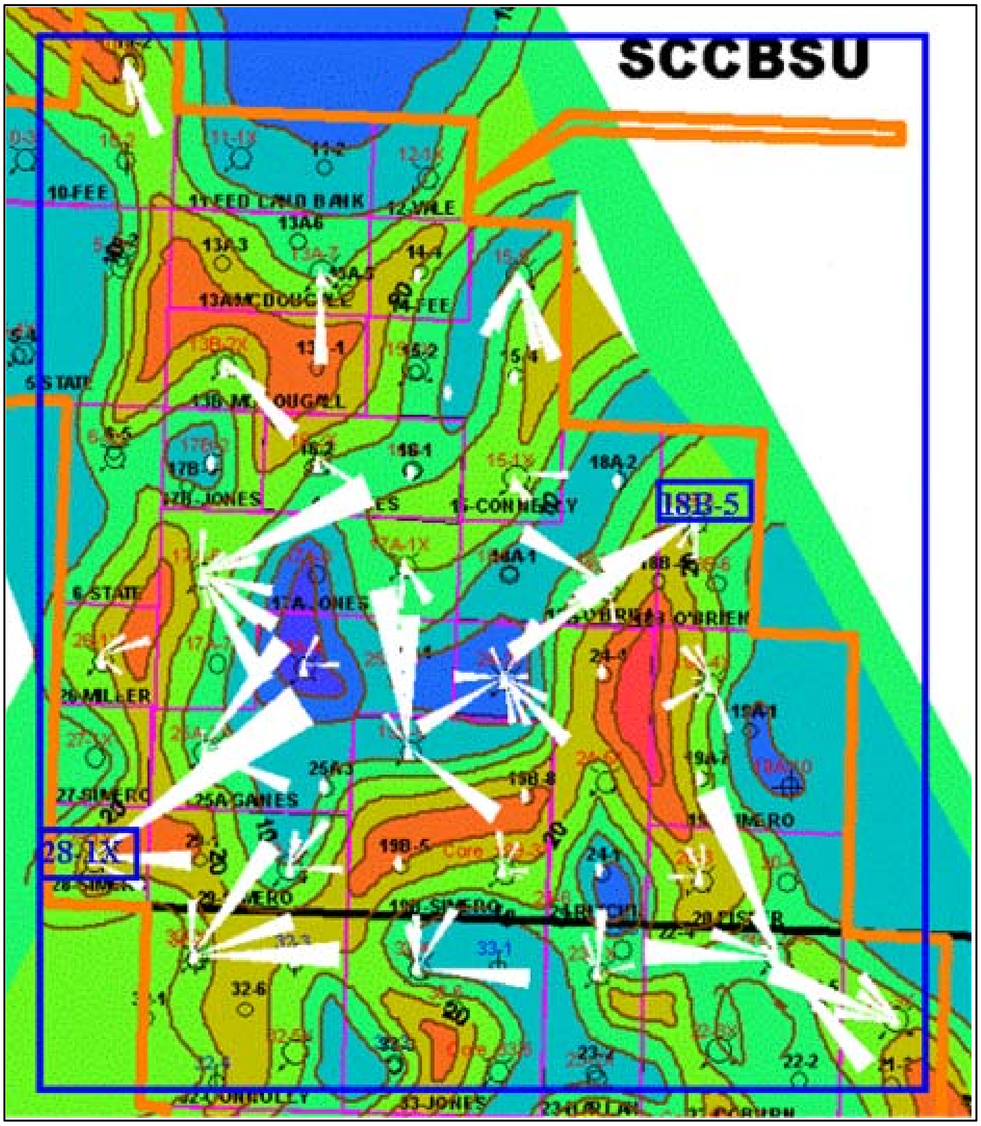


Fig. 28. North region QRI-BEG net-sand thickness map with arrow plot overlaid. Note the strong connectivity between the wells 28-1X, in the south-west area, with producer 18B-5, to the north-east.

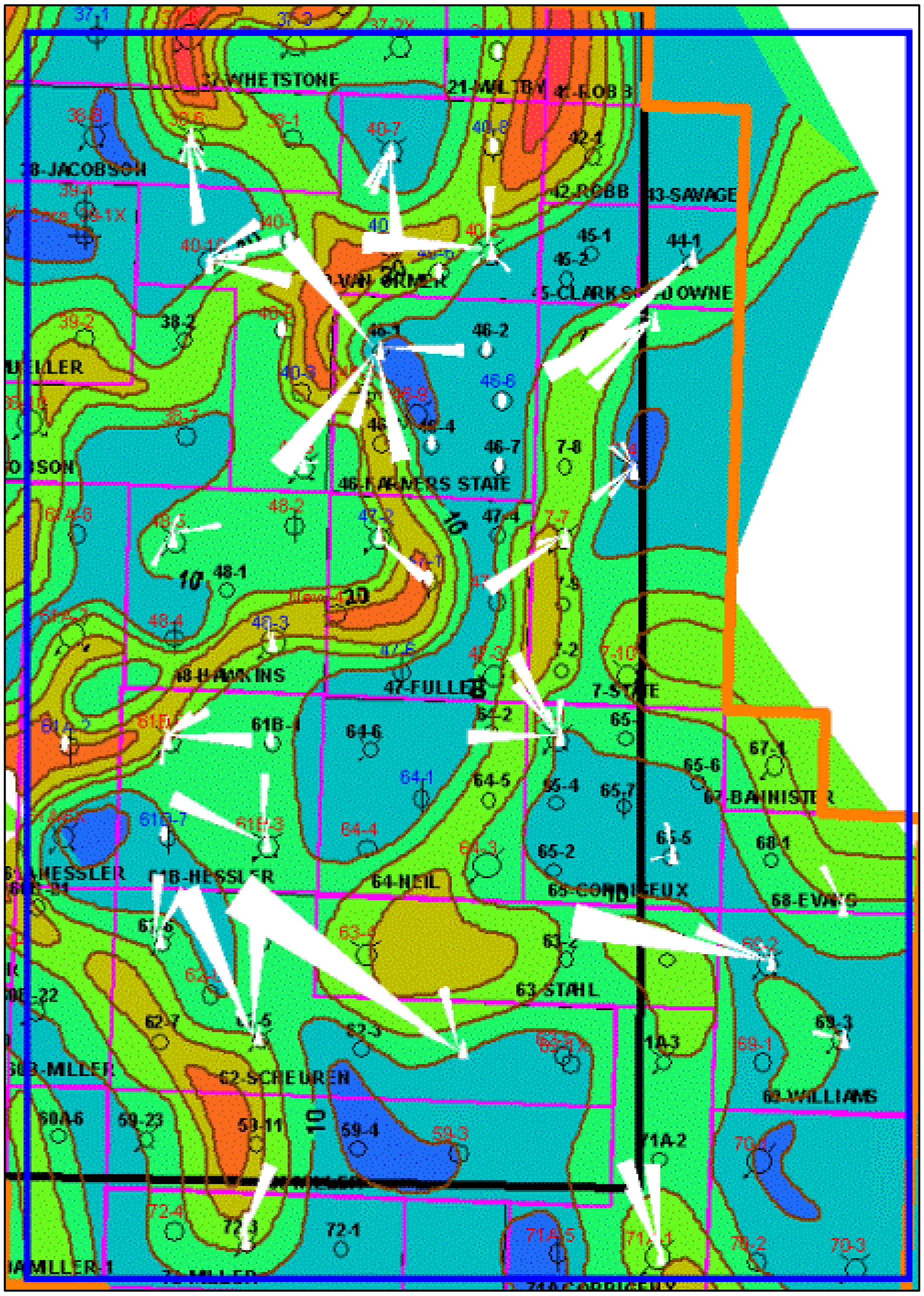


Fig. 29. North-central region QRI-BEG net-sand thickness map with arrow plot overlaid.

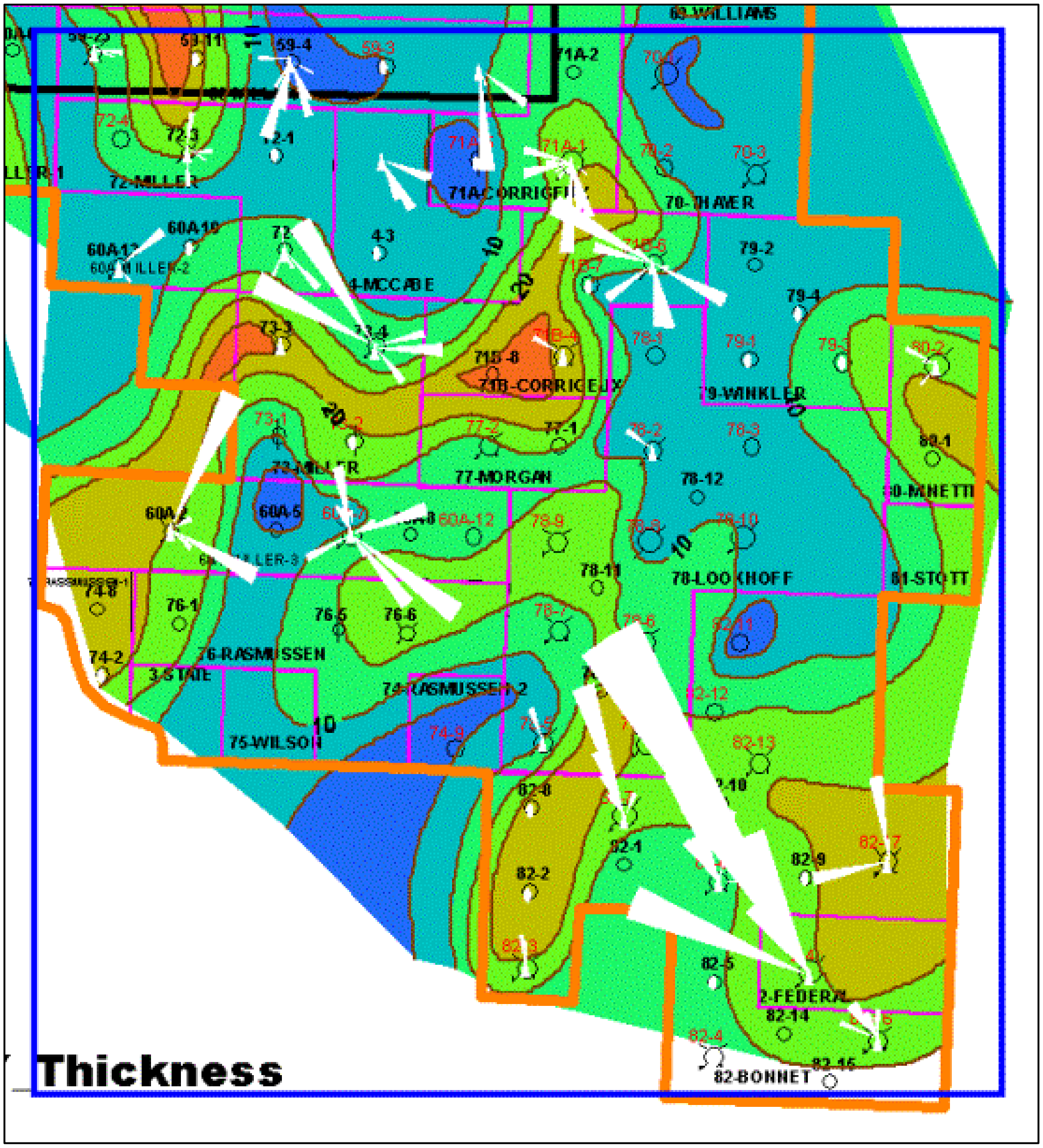


Fig. 30. South region QRI-BEG net-sand thickness map with arrow plot overlaid.

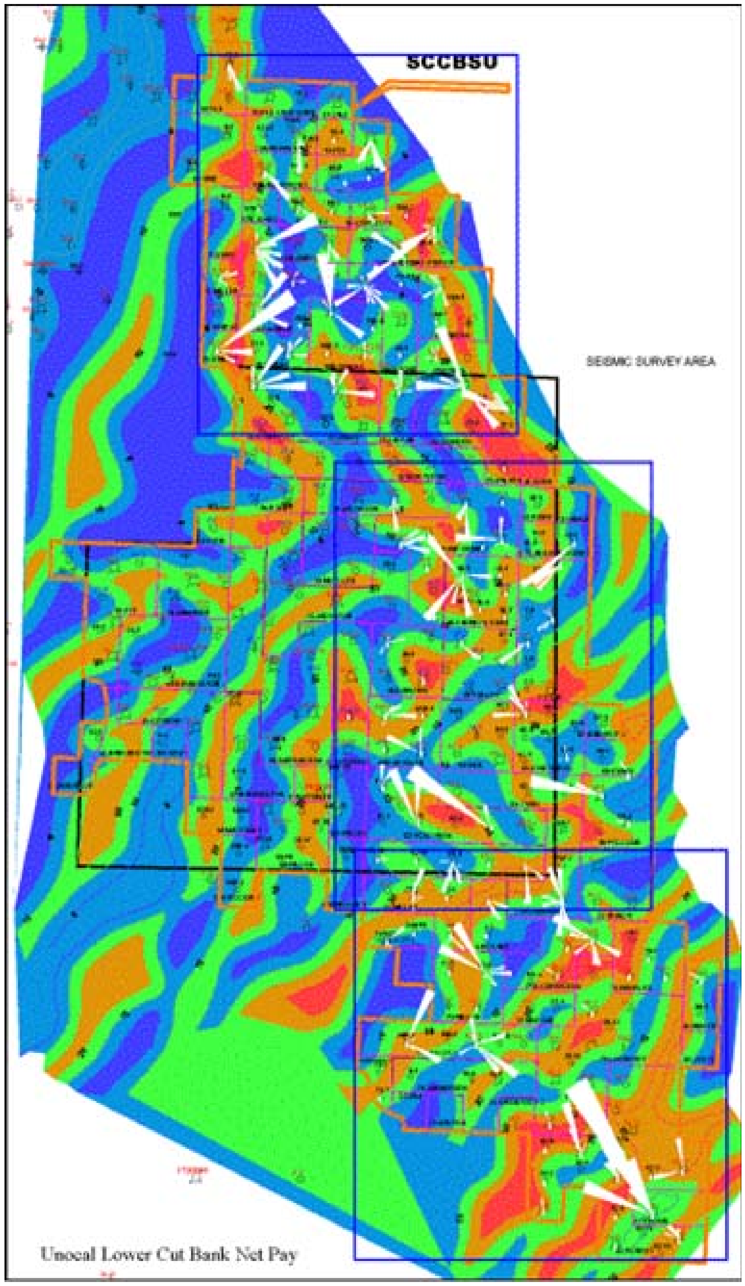


Fig. 31. SCCBSU net-thickness map (Unocal vintage) with arrow plot overlaid. Observe the poorer agreement of the arrows with net-thickness orientation compared to the net-thickness maps of Figs. 28-30.

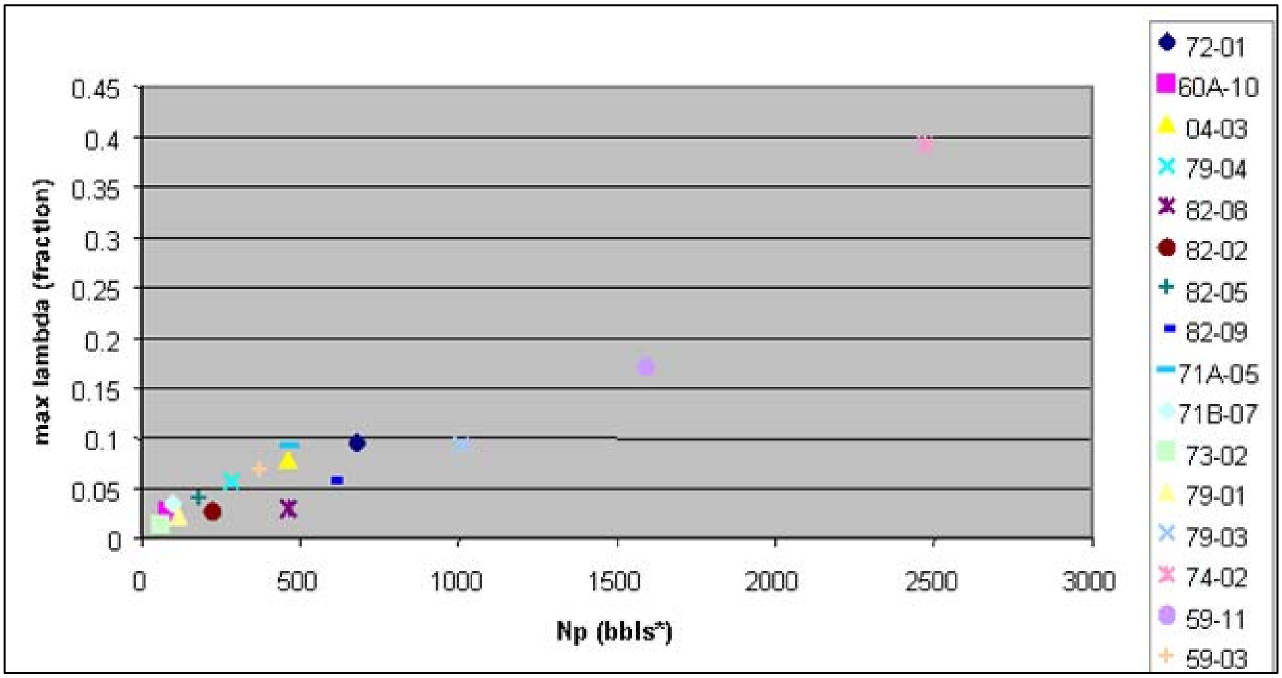


Fig. 32. Maximum λ and cumulative oil show some direct proportionality for producing wells in the South region.

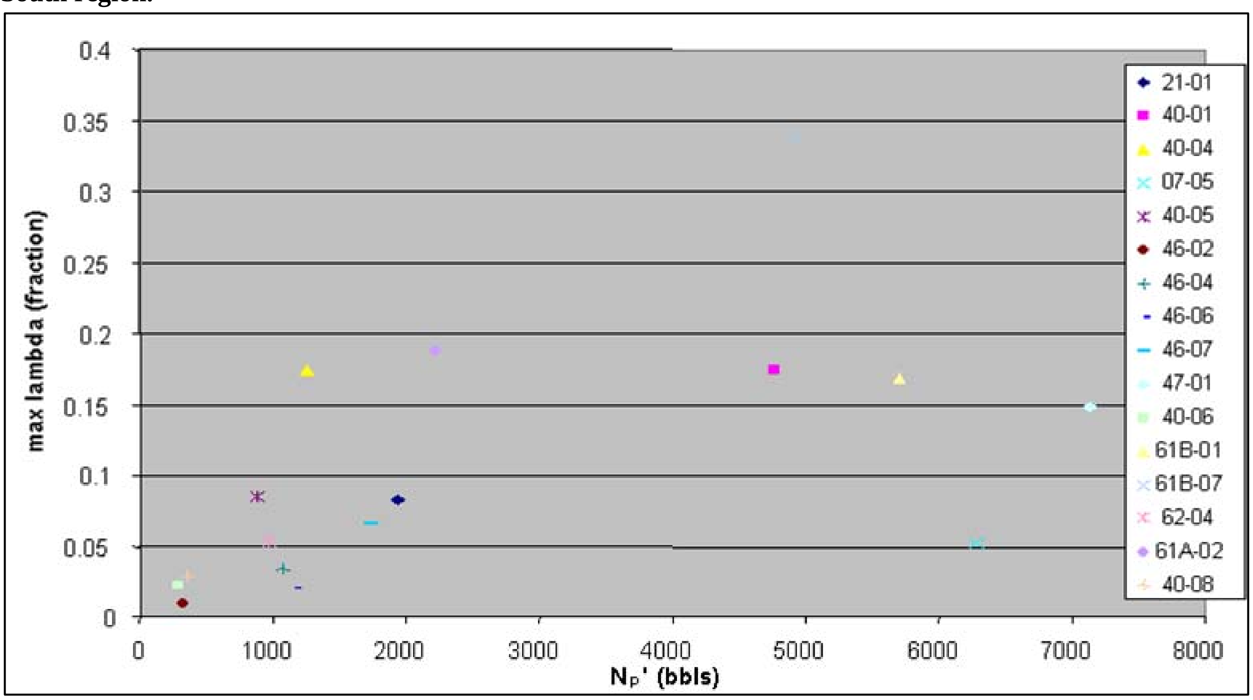


Fig. 33. Maximum λ and cumulative oil show some direct proportionality for producing wells in the North-central region.

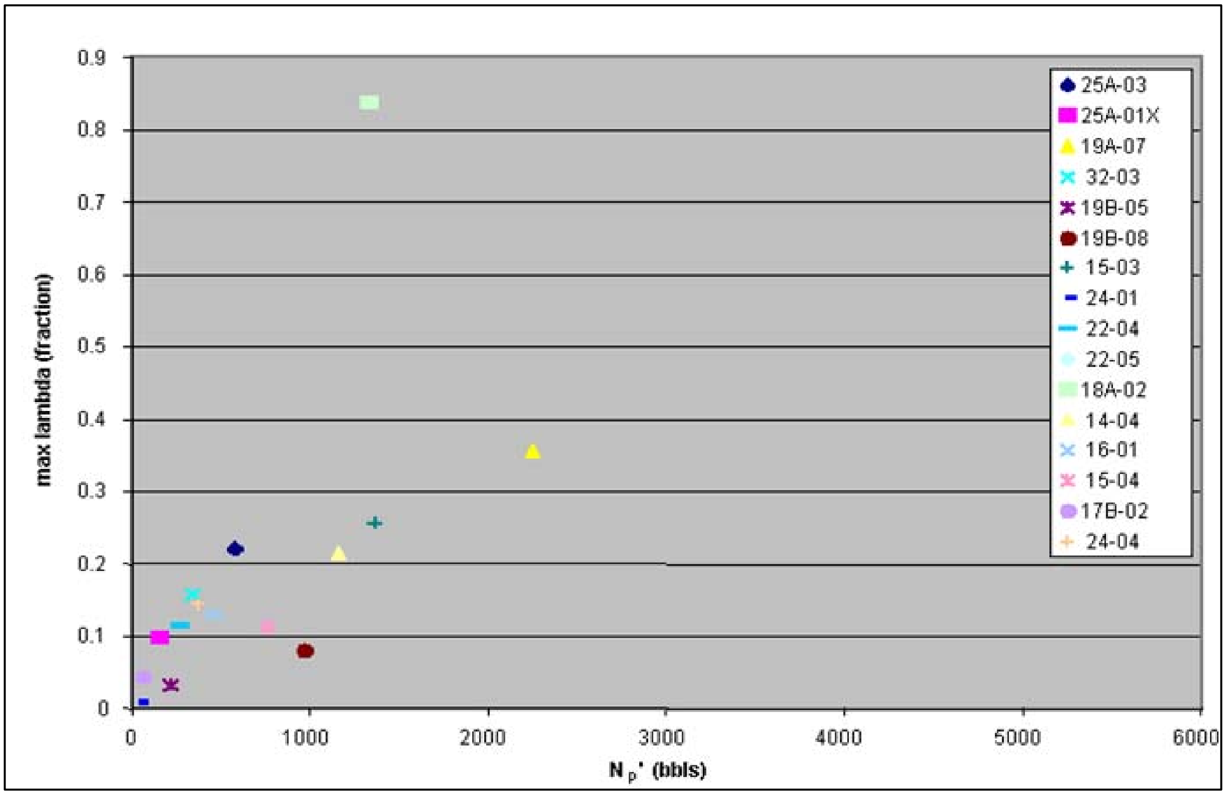


Fig. 34. Maximum λ and cumulative oil show some direct proportionality for producing wells in the north region.

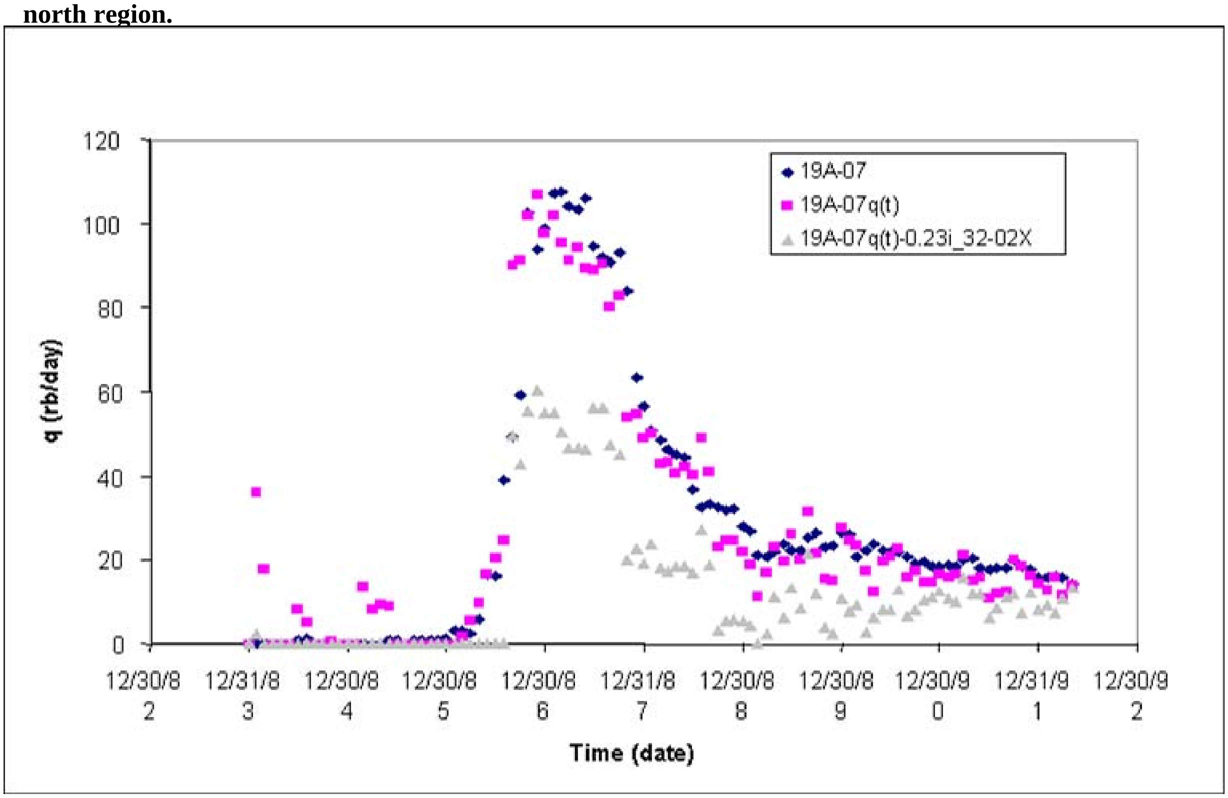


Fig. 35. North region – actual (blue diamonds) and predicted (red boxes) production from well 19A-07. Eexclusion of the contribution of injector 32-02X from the production of well 19A-07 (grey triangles) results in a large discrepancy with the calculated production

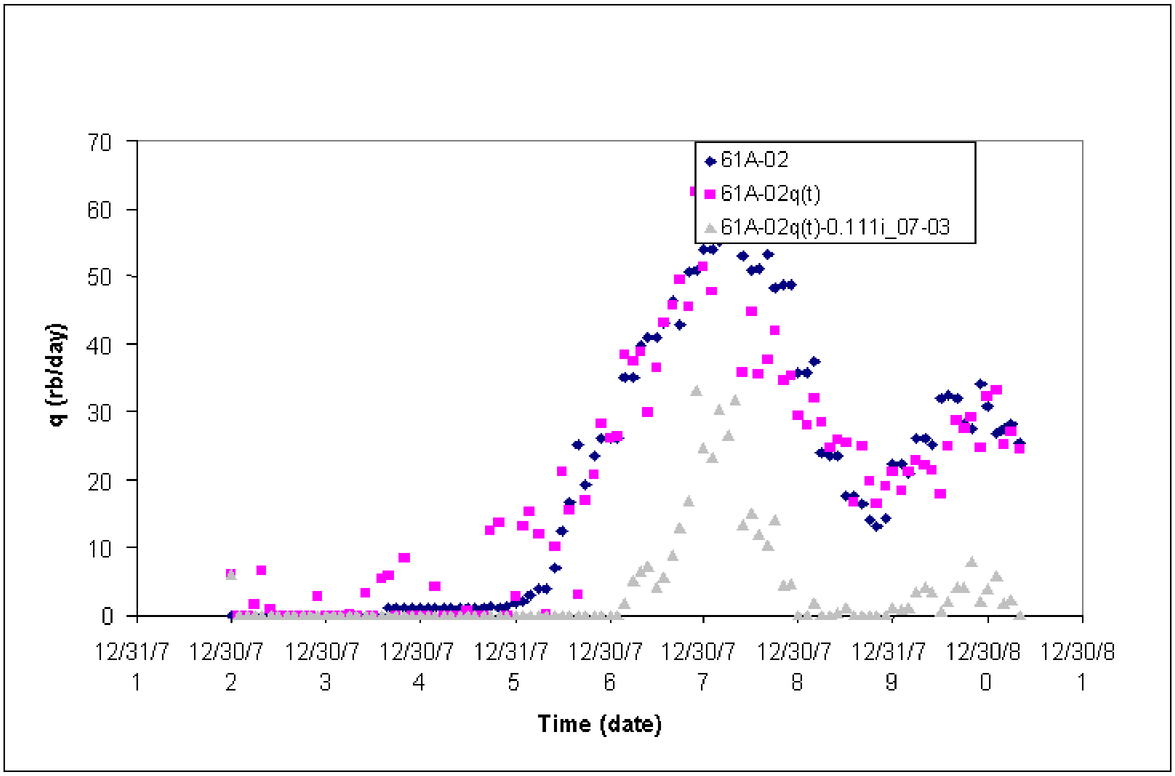


Fig. 36. North-central region –actual (blue diamonds) and predicted (red boxes) production from well 61A-02. Exclusion of the contribution of injector 07-03 from the production of well 61A-02 (grey triangles) results in a large discrepancy with the calculated production.

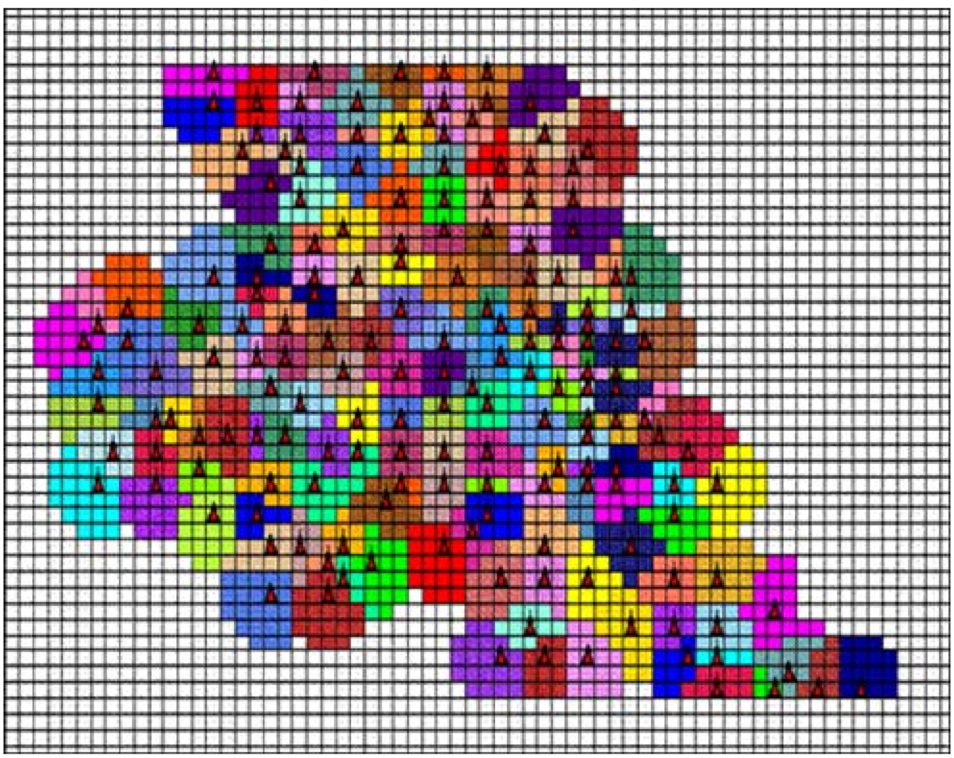


Fig. 37 Permeability regions depicted around each individual well.

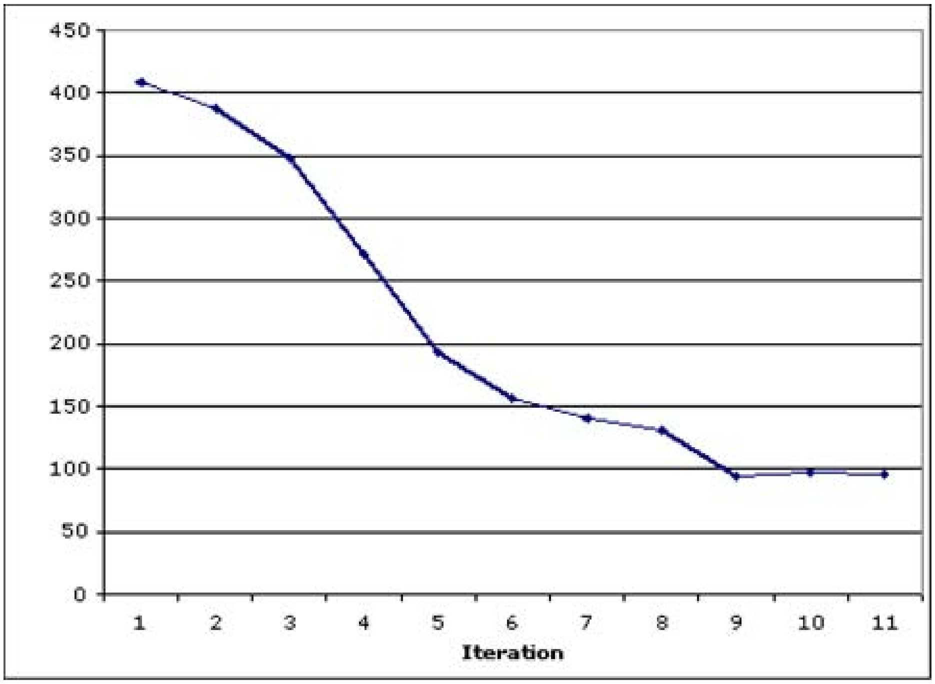
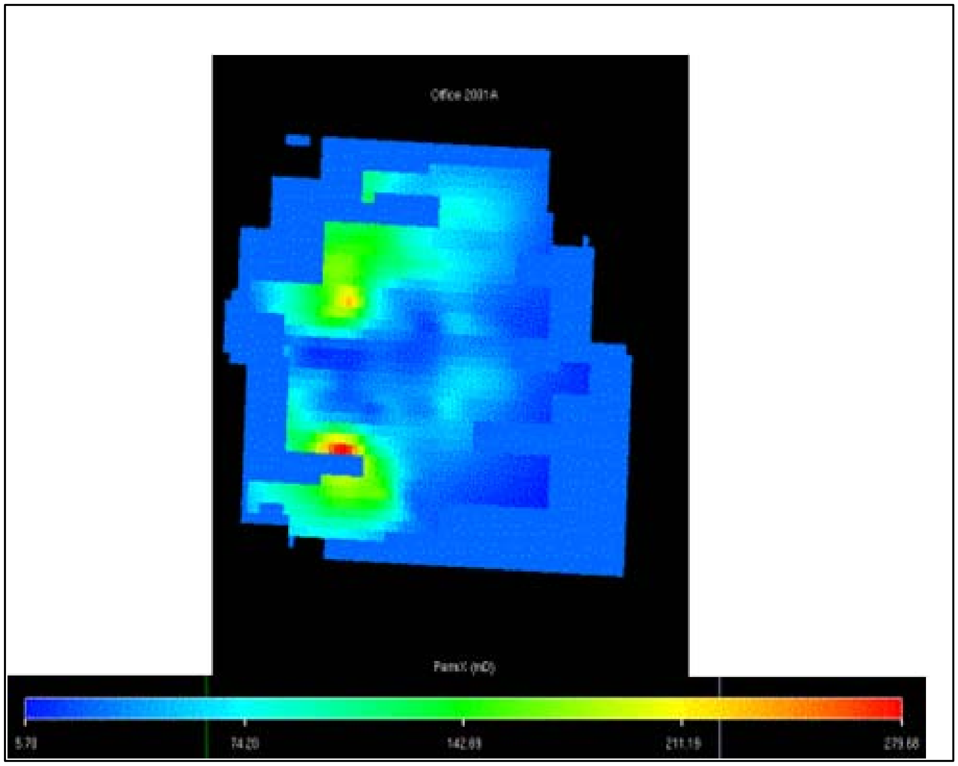


Fig. 38 Regression performance. Convergence obtained after 9 iterations.



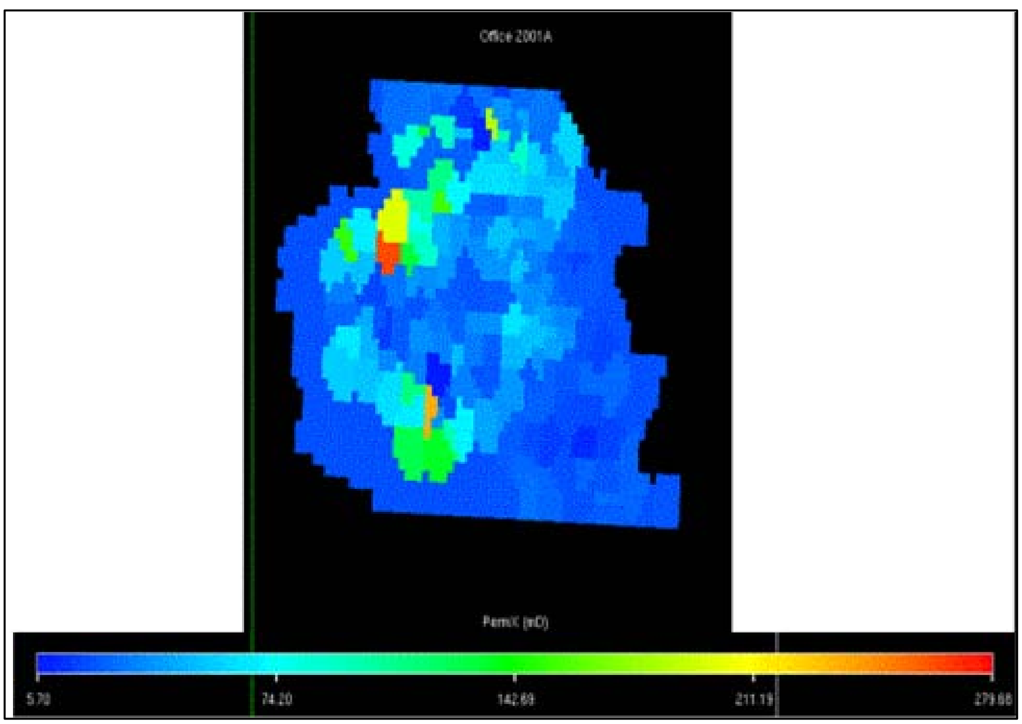
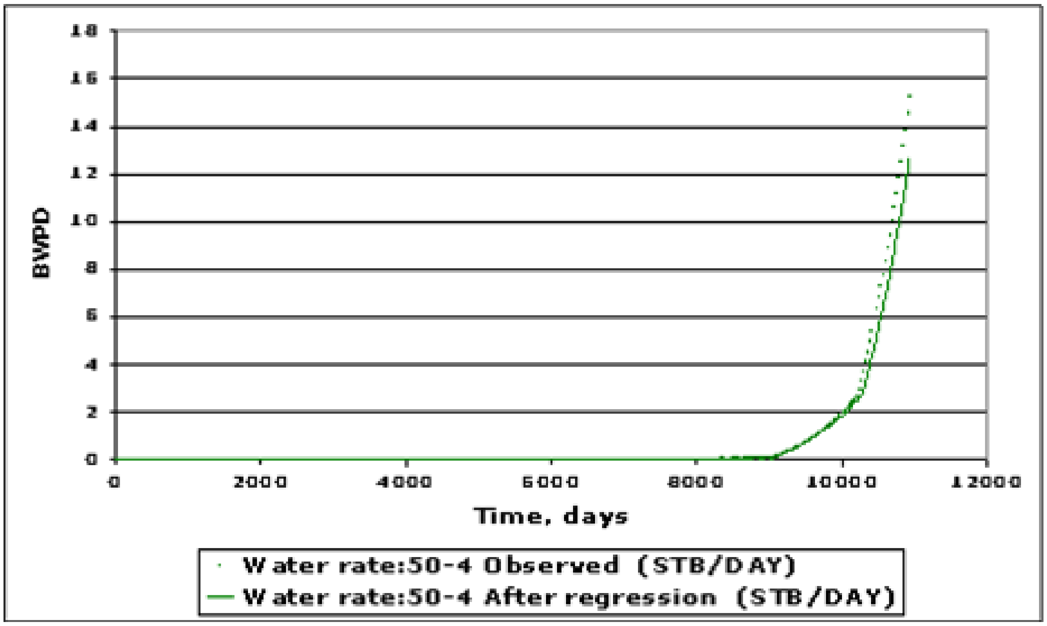


Fig. 39 - Comparison of permeability maps. To the top (a) is the map used to generate the observed production data and to the bottom (b) is the map obtained after the regression.



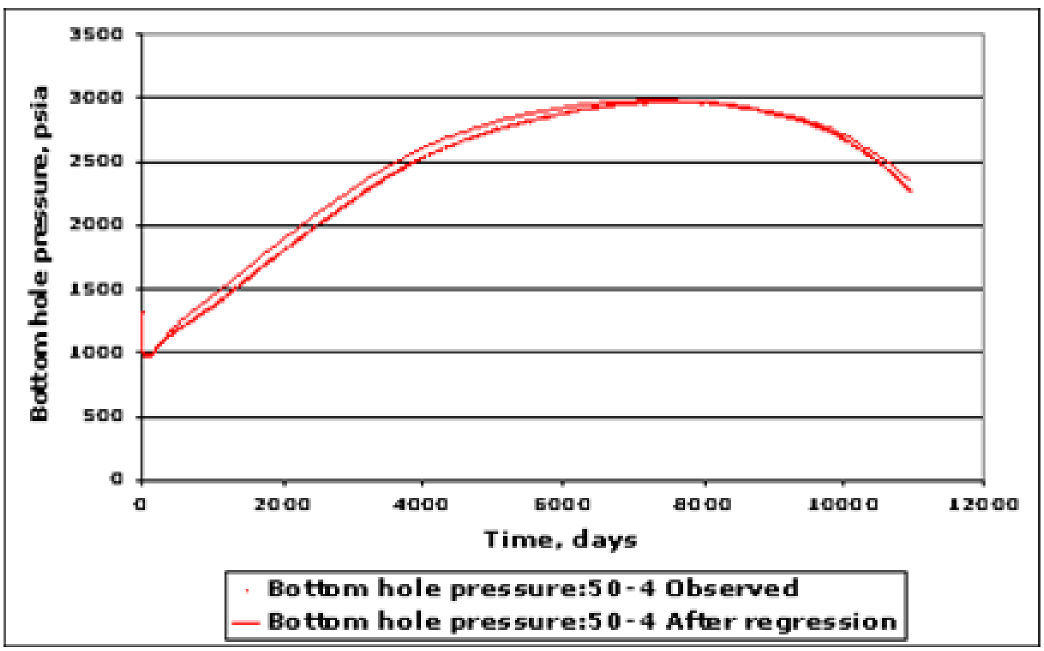
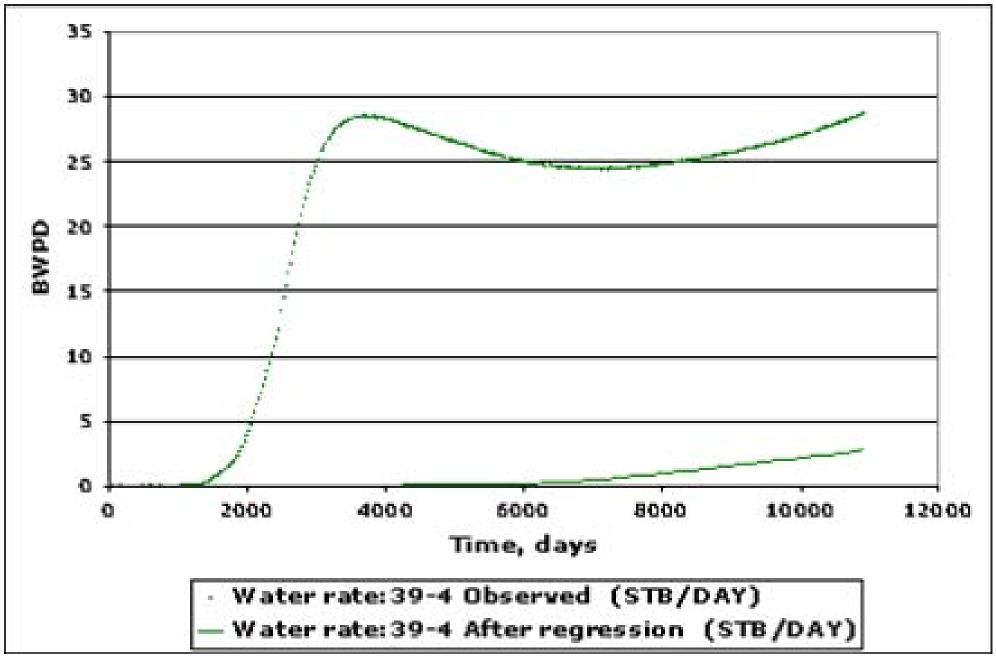


Fig. 40 - Best matched well for water production (top) and pressure (bottom) after the regression.



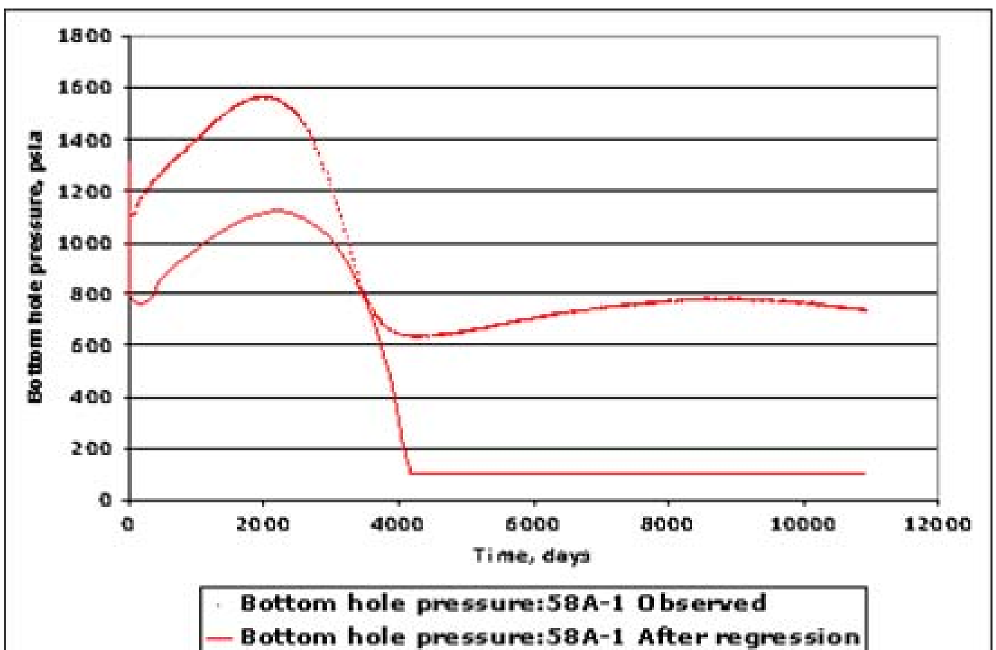


Fig. 41 - Worst matched well for water production (top) and pressure (bottom) after the regression.

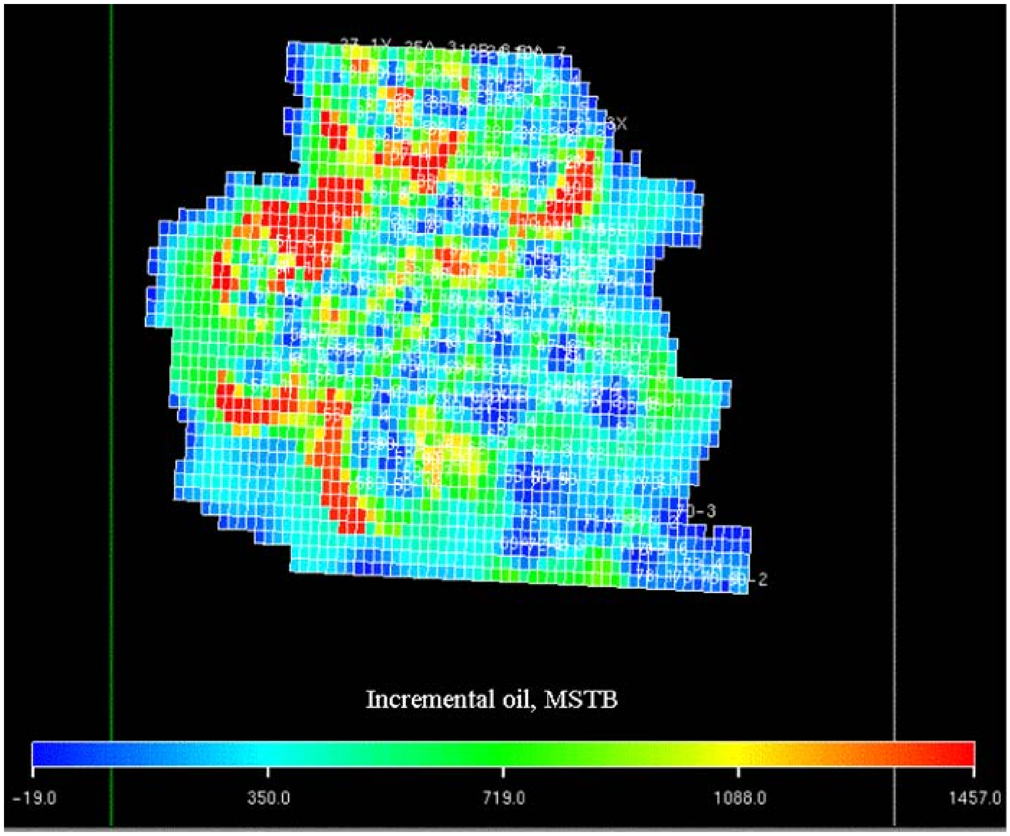


Fig. 42 - Infill incremental oil recovery with regressed permeability field, synthetic case.

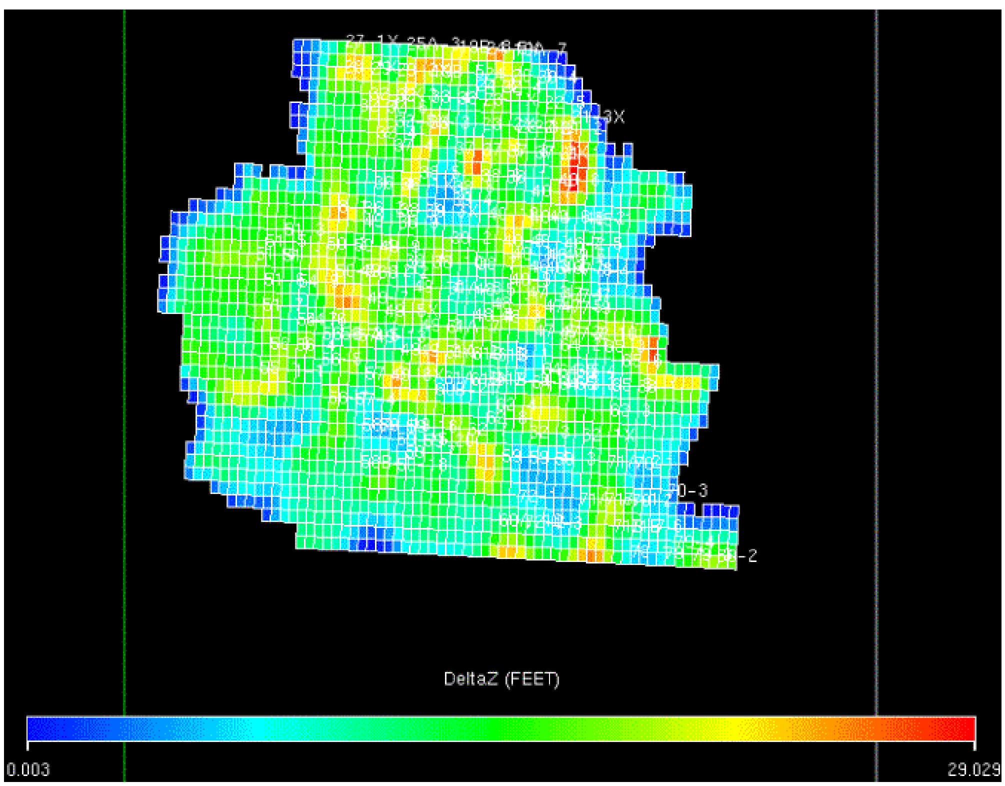


Fig. 43 - Net pay map.

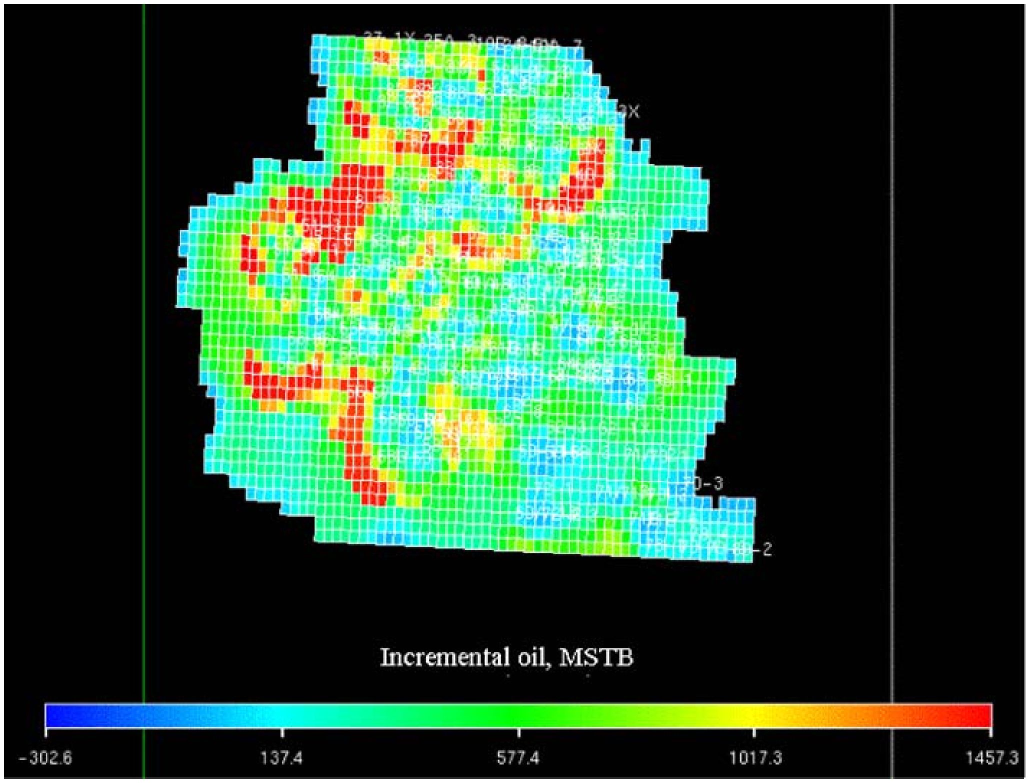


Fig. 44 - Infill incremental oil recovery with known permeability field, synthetic case.

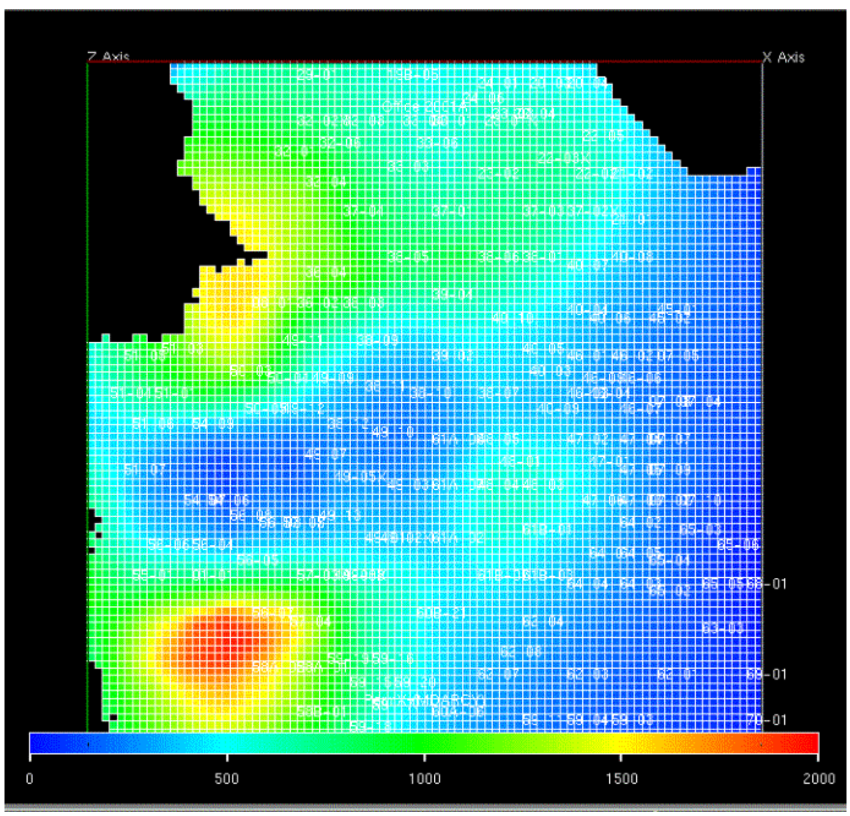


Fig. 45 - Permeability map for actual case prior to regression.

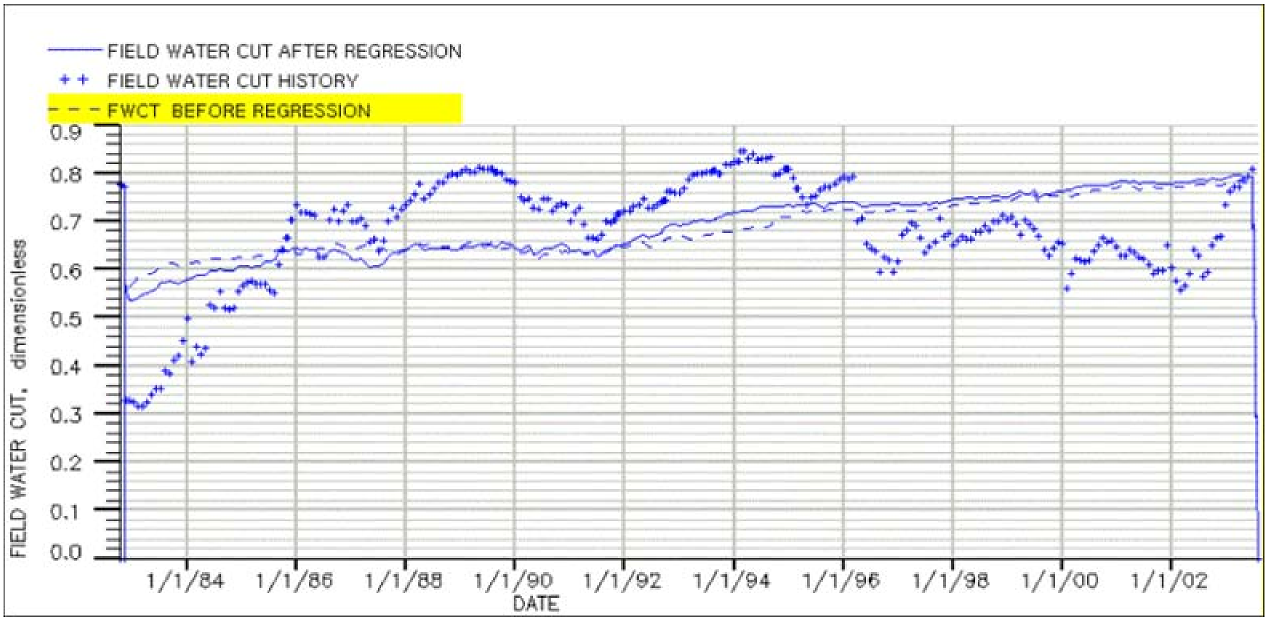


Fig. 46 - Match of field water cut for the actual case, after fieldwide matching but prior to individual well regression.

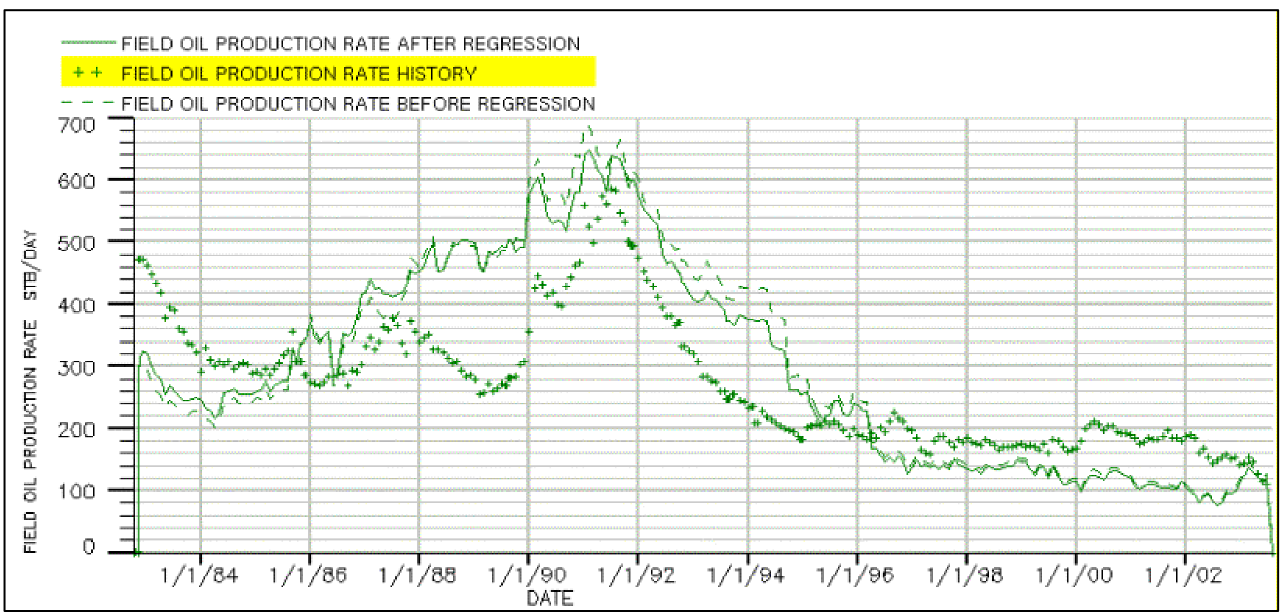


Fig. 47 - Match of field oil production rate for the actual case, after fieldwide matching but prior to individual well regression.

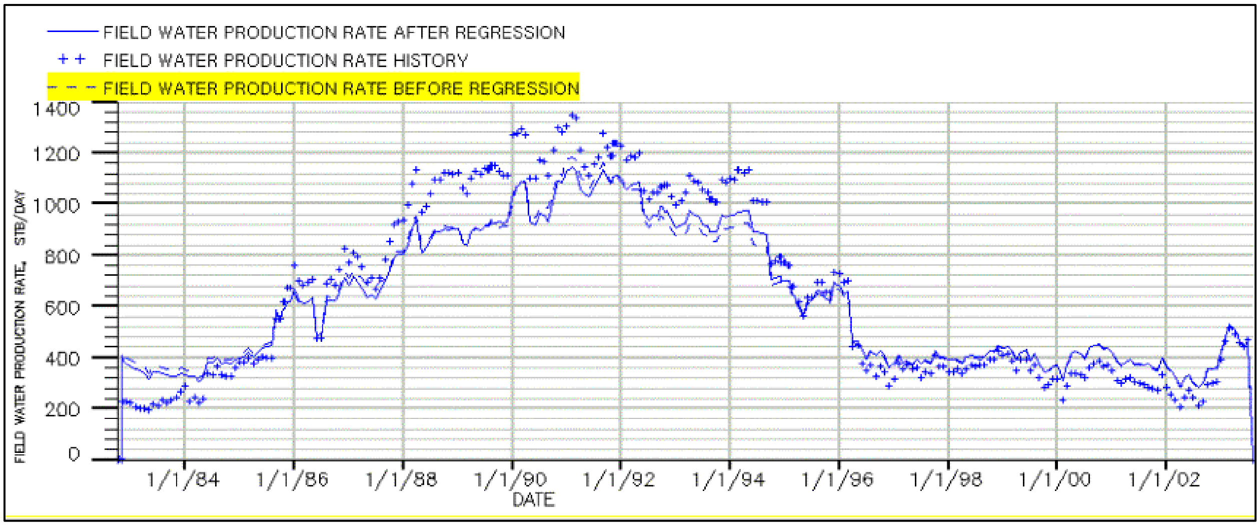


Fig. 48 - Match of field water production rate for the actual case, after fieldwide matching but prior to individual well regression.

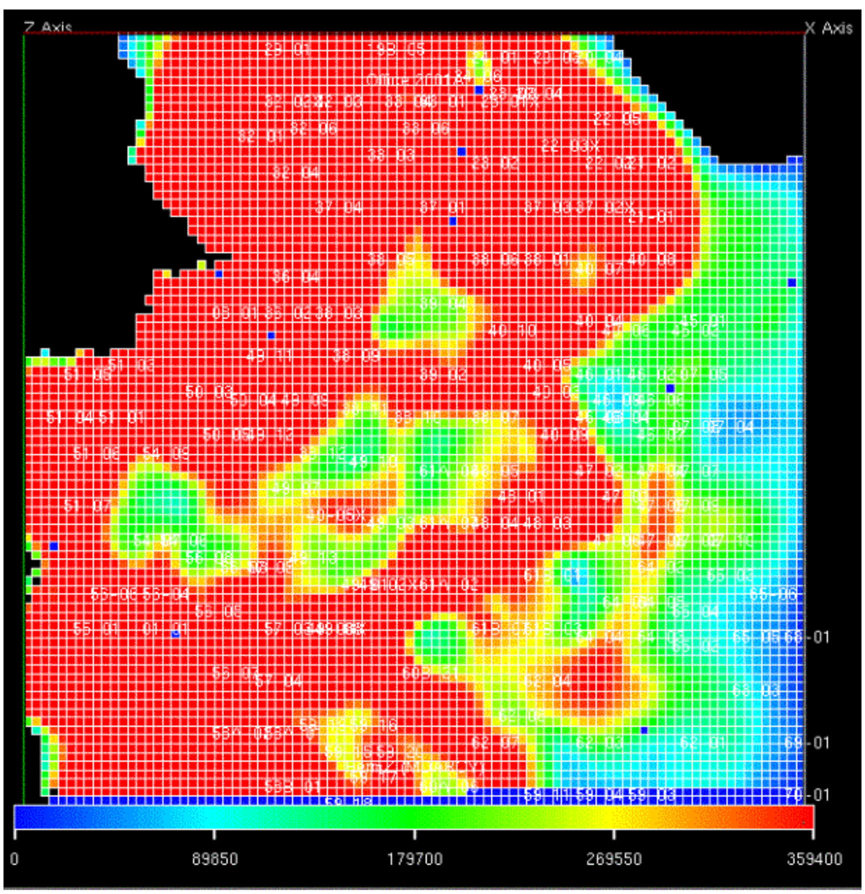


Fig. 49 - Map of infill incremental oil recovery for the actual case.

Development of Diagnostic Techniques to Identify Bypassed Gas Reserves and Badly Damaged Productive Zones in Gas Stripper Wells in the Rocky Mountain Laramide Basins

Final Report
May 15, 2001 to July 15, 2003

Contract No. 2039-IDT-DOE-1025
Stripper Well Consortium

Prepared by:

Innovative Discovery Technologies, LLC

Principal Investigator, Ronald C. Surdam

July 15, 2003

DISCLAIMER

Overview

The northern Rocky Mountain Laramide Basins (RMLB), especially in Wyoming, contain a huge, bypassed, underpressured gas resource that presently is penetrated, severely damaged, or commonly bypassed when operators drill to deeper, traditional overpressured gas assets. Most mud programs used to drill these “basin-center” targets are overcompensated during penetration of the gas-charged underpressured section, which occurs between normally pressured and overpressured rock/fluid systems. This approach results in stripper well gas production from severely damaged, underpressured reservoir rock, or completely bypassed pay zones; explaining in part why Wyoming leads the Nation in the increase of gas stripper wells (1909 gas stripper wells in 1999 and 10,321 gas stripper wells in 2001).

The largest gas fields in Canada (Elmworth, Milk River, Hoadley) and the largest composite domestic Rocky Mountain gas field, the San Juan Basin, are underpressured. The potential for underpressured gas production in Wyoming is huge, but remains bypassed or underdeveloped. To exploit this energy resource, RMLB operators must recognize the magnitude of the undeveloped, underpressured gas resource, and then must treat underpressured gas prospects as priority targets, instead of as incidental targets penetrated during drilling of deeper, traditional overpressured gas resources.

The goal of the work described in this report was to provide the techniques necessary to identify bypassed gas and badly damaged productive zones in RMLB marginal gas wells. This goal was achieved by first examining individual wells to identify the problem, then developing diagnostic tools, and, finally, applying and testing these tools on a regional scale. Use of the technology developed in this project allows operators to predict qualitatively under- and overpressured terrains prior to drilling, thereby allowing them to avoid bypassing gas pay and to minimize drilling and completion damage.

In order to establish the magnitude of the problem of bypassed or damaged pay zones in RMLB marginal wells detected on the scale of a well, one must evaluate the problem on a regional basis. For this regional exercise, the Wind River Basin was chosen because of data availability.

Well-Specific Investigation

The study area consists of the Wind River and Greater Green River basins (Figure 1), which together contain 5,537 gas wells, of which we have access to complete log suites and production data for 375 wells. From the 375 wells, 45 test wells were chosen for the proposed work, including commercial gas wells, gas stripper wells, and abandoned gas wells. For each of the 45 wells, the following tasks were completed:

- Determination of the thickness of the underpressured zone beneath the pressure surface boundary from sonic and mud logs, and acquisition of DST and RFT data where available.
- Evaluation of complete log suites for each well, with special emphasis on determining the relationships among the velocity inversion surface (i.e., sonic log), mud log, high resistivity, neutron and density porosity (i.e., gas crossover), gamma ray, and caliper logs.
- Compilation of production data patterns and trends for the 45 wells.
- Evaluation of each well type (stripper, abandoned, gas) using the compiled data:
  - Thickness of underpressured zone
  - Distribution of gas-charged sandstones and fractured shale
  - Production characteristics
  - Distribution of the rock-fluid system that has been exposed to overcompensated mud weight (e.g., potential damage zone)
- Integration of the data and determination of the potential for bypassed gas and damaged productive zones in each of these three types of wells and determination of the most

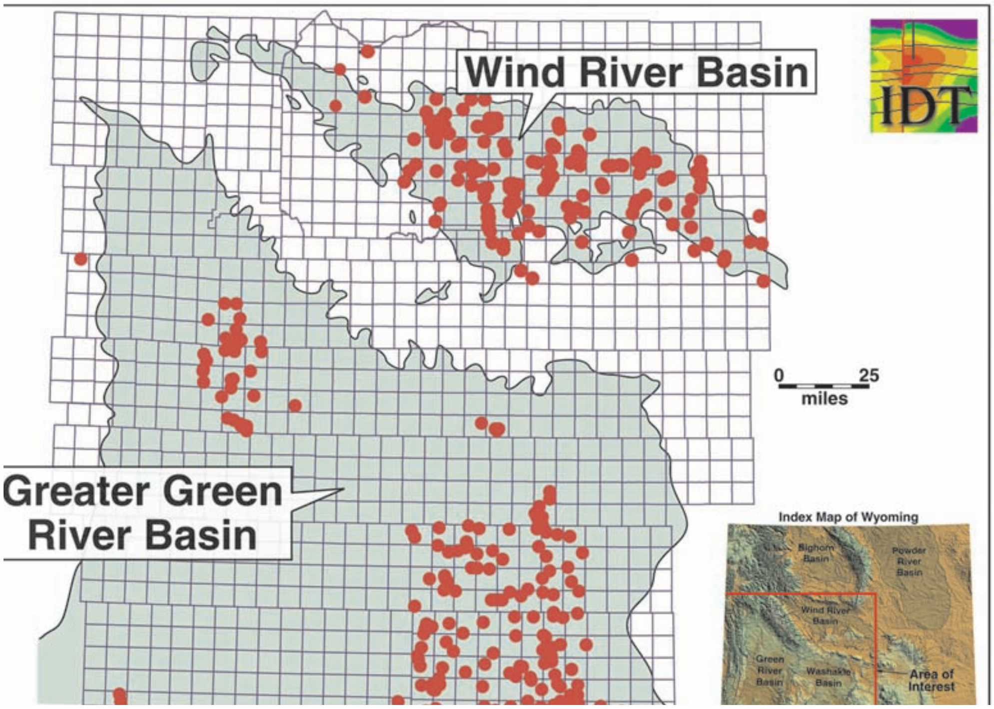


Figure 1. Index map of the study area, the Greater Green River and Wind River basins, WY.

effective, efficient routines for identifying bypassed gas and damaged pay in the gas stripper and/or marginal wells.

Data Collection

Wellhead information was assembled and sonic and mud logs digitized for each of the 45 wells (Table 1). Gamma ray, neutron porosity, density porosity, resistivity, and caliper logs were acquired and have been evaluated. Available initial production, production zone, DST, and RFT data also was acquired.

Determination and Delineation of the Fluid-Flow System

The fluid-flow systems in the RMLB are known to be compartmentalized, both on a regional and local scale. Regionally, these basins are divided into at least three large compartments; locally, these large compartments are subdivided into several smaller compartments (Figure 2). The boundary between the normally pressured, water-saturated fluid system and the underlying anomalously pressured, gas-charged fluid system is characterized by a significant sonic/seismic velocity inversion, which corresponds to the regional pressure surface boundary. Below this boundary, the velocity can be up to 2000 m/s slower than that predicted by the *ideal* regional velocity/depth gradient. The regional pressure surface boundary is especially important because in the RMLB, a huge portion of the cumulative gas production, including most gas stripper wells, is from reservoirs spatially located below, but within 2000 feet of the boundary (Surdam, 1997; Surdam, 2001a; Surdam, 2001b; Surdam, 2001c; Surdam et al., 1994, 2001).

Sonic logs from 45 wells (Table 1), combined with DST, RFT, and mud data, were used to determine the fluid-flow regime (i.e., the pressure surface boundary and the underpressured zone below this boundary). Anomalous velocity profiles were generated for all 45 wells (Figures 3 through 5). The anomalous velocity was calculated by systematically removing the

Table 1. List of wells used in this project.

Greater Green River Basin

Well Name	API #	Township	Range	Section	Status
Canyon Creek Unit 32	4903722827	T12N	101W	9	SI
Cherokee Ridge Federal 1	4903720518	T12N	R96W	15	A
New Moon Unit 1	4903722317	T13N	R95W	13	SI
Federal 3-5	4903722029	T14N	R100W	5	A
CEPO Lewis 21-18	4903724185	T14N	R95W	18	Gas
Windmill Draw Unit 1	4903721071	T15N	R94W	14	SI
Lario Federal 33-14	4903724076	T15N	R94W	15	SI
Mull Federal 44-18	4903724124	T15N	R94W	18	Gas
Wester Federal 33-6	4903724352	T15N	R94W	6	Gas
Mulligan Draw Unit 6	4903722912	T15N	R95W	25	Gas
Coal Gulch Unit H 1	4900720662	T17N	R93W	2	Gas
Champlin 256	4903720763	T17N	R96W	3	A
C. G. Road Unit 26-3	4903723919	T21N	R94W	26	Gas
Beaver Mesa 1-7	4903720416	T24N	R102W	7	A
Federal 21-1	4903722021	T24N	R103W	21	Gas
Freighter Gap Unit 1	4903721904	T24N	R12W	13	SI
Freighter Gap Unit 2	4903721982	T24N	R12W	12	A
Federal 1-1	4903722261	T24N	R14W	1	A
Packsaddle Unit 1	4903721425	T25N	R103W	24	A
Federal Q 1	4903721096	T25N	R96W	28	Gas
Musketeer Unit 1	4903721966	T26N	R101W	8	A
Golden Rod Unit 1	4903520601	T27N	R109W	30	A
Wardell Federal 1	4903520342	T28N	R108W	9	SI
Tot Unit 31-22	4903521652	T28N	R109W	22	Gas
Yellow Point Federal 11-13	4903521887	T28N	R109W	13	Gas
Stud Horse Butte 13-27	4903521359	T29N	R108W	27	Gas
Stud Horse Butte 5-26	4903521374	T29N	R108W	26	Gas
Wagon Wheele 1	4903520124	T30N	R108W	5	SI
West Pinedale 1	4903520348	T30N	R109W	33	SI

Wind River Basin

Shoshone Arapahole Tribal 534	4901320612	T1S	R2E	2	SI
Ocean Lake Tribal	4901321430	T2N	R4E	8	SI
Tribal 24-11	4901320748	T3N	R3E	11	A
Ocean Lake Tribal 1-15	4901321312	T3N	R3E	15	Gas
Tribal MR 30-13	4901321772	T4N	R3E	30	Gas
Tribal Chevron 30-11	4901320725	T4N	R3E	30	Gas
Tribal Sand Mesa 2	4901320800	T4N	R4E	24	Gas
Coastal Owl Creek 1	4901321077	T5N	R3E	26	SI
Ryan Hill Unit 1	4902520002	T32N	R84W	35	A
HSR Steele 16-31	4903521725	T34N	R109W	31	SI
Twindale 1	4902521344	T34N	R87W	15	Oil
Federal USA 17-1	4901320961	T34N	R94W	17	Oil
Wild Horse Butte 1-16	4902522015	T35N	R88W	16	A
Nawking Draw Unit 2	4901320488	T35N	R90W	25	A
Horseshoe Creek Federal 1	4901321546	T35N	R92W	26	Si
Fuller Reservoir Unit 2	4901320565	T36N	R94W	25	SI

2¹/₂D Anomalous Velocity Model, Western Wind River Basin

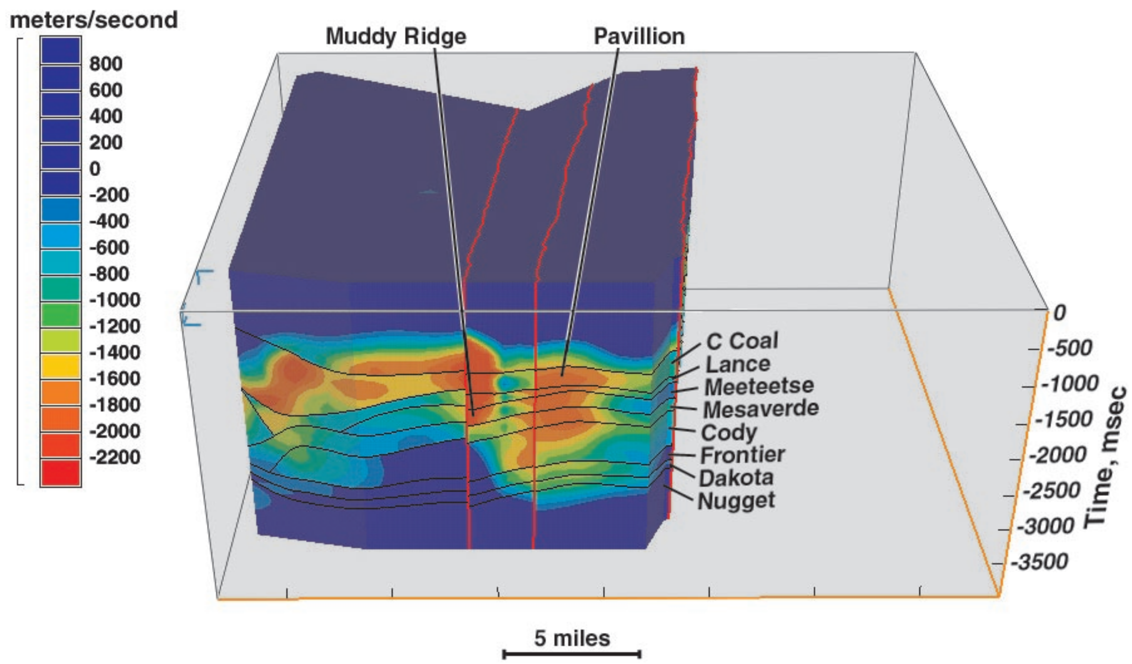


Figure 2. An east-west cross section cut through a 2 ½ D anomalous velocity model showing pressure compartmentalization in the Western Wind River Basin, Wyoming. Red and yellow areas indicate an anomalously pressured and gas-charged rock/fluid system.

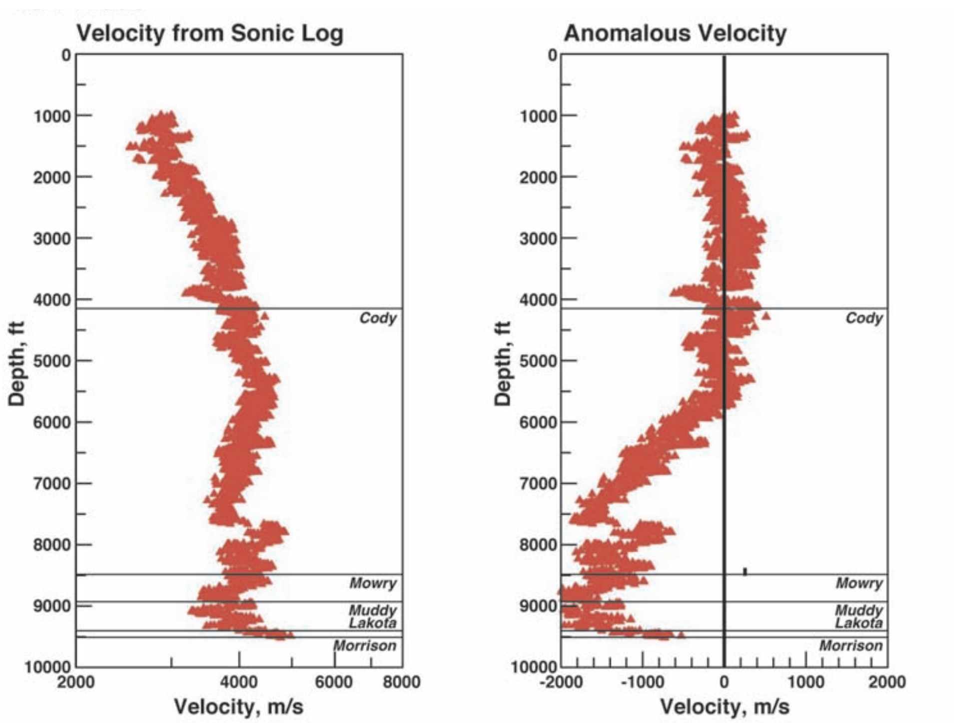


Figure 3. Sonic velocity and anomalous velocity profiles for a well from the western Wind River Basin, WY. The pressure surface boundary is at 5700 ft.

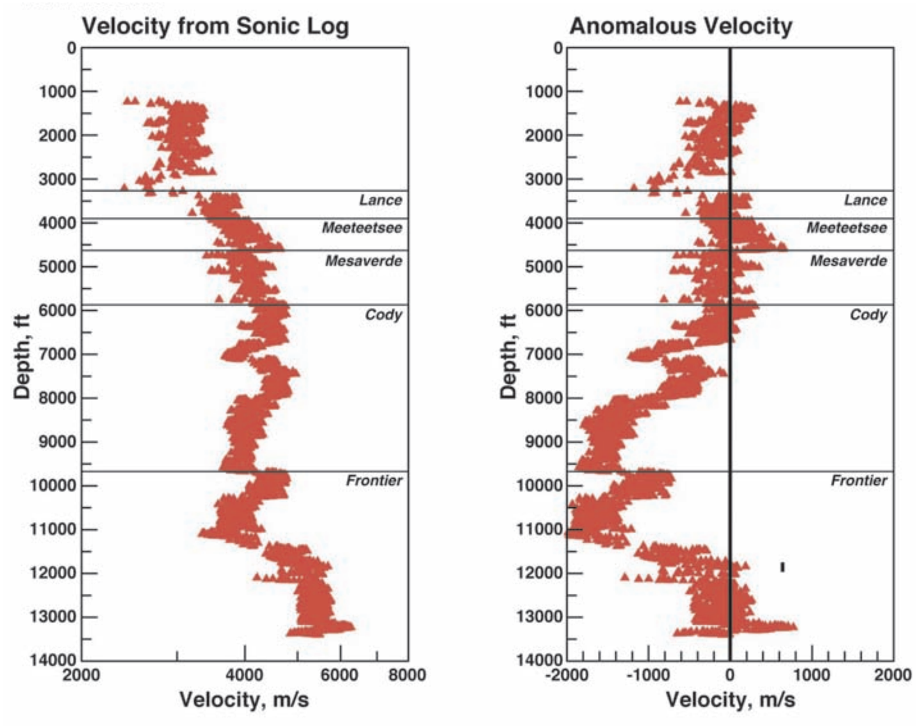


Figure 4. Sonic velocity and anomalous velocity profiles for a gas well from the western Wind River Basin. The pressure surface boundary is at 6600 ft.

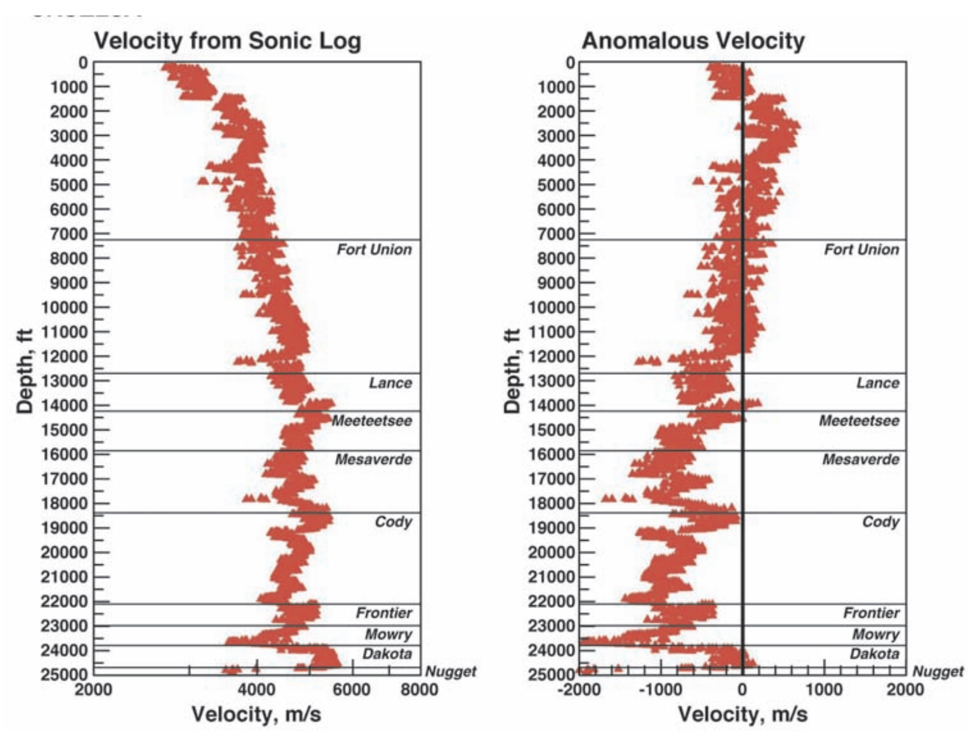


Figure 5. Sonic velocity and anomalous velocity profiles for a well from the northwestern Wind River Basin. The pressure surface boundary is at 11,800 ft.

ideal regional velocity-depth gradient from the sonic velocity profiles. Rocks with normal velocity/depth trends (i.e., falling on or near the velocity/depth hydrostatic gradient) are characterized by normal pressure and a water-dominated, single-phase fluid-flow system, whereas rocks with anomalous velocity are characterized by anomalous pressure (overpressure or underpressure) and a multiphase fluid-flow system (Surdam et al., 1997).

These anomalous velocity profiles are used to determine the: (1) pressure surface boundary, (2) interval with anomalous pressure, and (3) gas-charged, anomalously pressured section (Figure 6). The gas-charged, underpressured section can be identified on the anomalous velocity profile by using the pressure data (i.e., DST, RFT, and mud log data) (Figure 7).

Determination of Badly Damaged Productive Zones

Because the pressure transition configuration present in the study area was poorly understood or unknown to drillers when many of the RMLB gas stripper wells were drilled (prior to 1990), operators, from experience, assumed they would encounter overpressuring at depth. The drillers' primary concern, with respect to safety and control of the well, was for a transition from normal to overpressure; consequently, they increased mud weights during drilling. However, in the RMLB, underpressuring is often encountered at depth; thus, many of these underpressured zones were drilled with overcompensated mud weights (Figures 6 and 7). In this drilling situation, the potential for bypassing or highly damaging productive zones was *significant* and resulted in wells that produced only a fraction of the available gas.

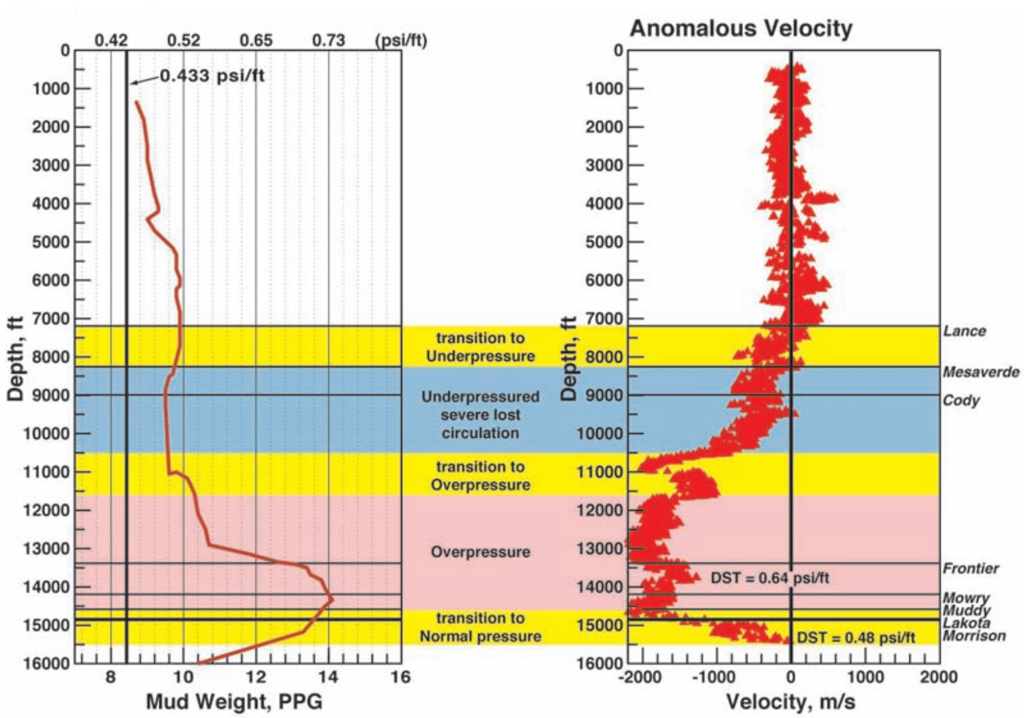


Figure 6. Mud weight profile and anomalous velocity profile for a well from the eastern Wind River Basin. The regional pressure surface boundary is at the top of Lance at 7200 ft depth. The underpressured zone is from 8250 to 10,500 ft depth. The mud weight used to drill the underpressured interval was 9.6 ppg, or significantly overcompensated.

In order to determine where badly damaged productive zones occur in the study area, mud logs were plotted with anomalous velocity profiles. For example, Figures 6 through 10, which include both mud weight profiles and anomalously velocity profiles, show how mud weights were overcompensated in the underpressured stratigraphic section. Figure 6 shows both profiles. Here, the regional pressure surface boundary occurs at the top of Lance at 7200 ft depth, and the underpressured zone occurs in the 8250 to 10,500 ft depth interval. The mud weight used to drill this gas-charged underpressured interval was 9.6 ppg, which was significantly overcompensated. Figure 7 shows both a mud weight profile and anomalous velocity profile; the regional pressure surface boundary occurs at 8000 ft depth in the Fort Union Formation, and the underpressured zone occurs in the 8000 to ~13,500 ft depth interval. A pressure gradient 0.39 psi/ft from DST is measured at the depth 10,000 ft, so the mud weights should have been less than the weight of water (i.e., < 8.4 ppg). The mud weights used to drill this underpressured interval were 8.6 to 9.2 ppg, also overcompensated. In Figure 8, the regional pressure surface boundary is within the Cody Formation at 6300 ft depth, and the anomalously pressured zone occurs within the 6300 to ~10,000 ft depth interval. The mud weights used to drill this anomalously underpressured interval were 8.9 to 9.4 ppg, again overcompensated; there is no indication that the upper potion of this anomalously pressured zone is overpressured, but instead is underpressured. Figure 9 is for a well from the Washakie Basin, Wyoming. The regional pressure surface boundary occurs at 6500 ft depth in the Fort Union Formation, and the anomalously pressured zone occurs from 6500 to DT. The mud weights used to drill this anomalously underpressured interval were 8.9 to 10.3 ppg, again, an overcompensated mud program.

It is clear from these preliminary results that the mud weights used to drill gas-charged underpressured sections were significantly overcompensated (and potentially damaged the zone) and were common in the both Greater Green River and Wind River basins (Figures 8 and 9). In fact, numerous gas-charged intervals were overcompensated with heavy mud. The logic for these conclusions is as follows:

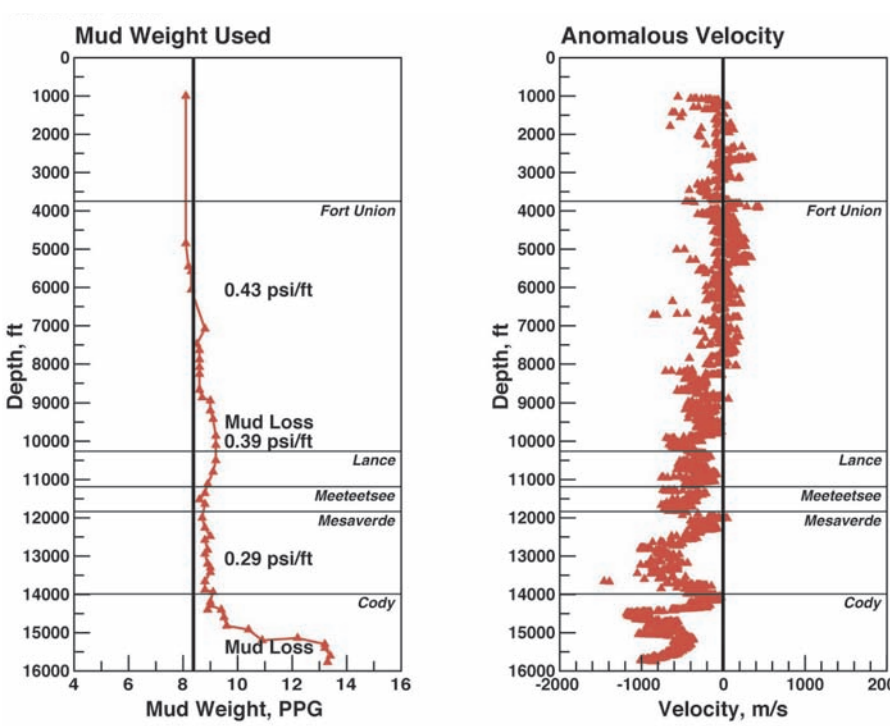


Figure 7. Mud weight profile and anomalous velocity profile for a well from the Wind River Basin. The regional pressure surface boundary occurs in the Fort Union Formation at 8000 ft depth. The underpressured zone is from 8000 to ~13,500 ft depth. A pressure gradient of 0.39 psi/ft from DST is measured at 10,000 ft depth, so mud weights should have been less than the weight of water (i.e., < 8.4 ppg). However, mud weights used to drill this underpressured interval were 8.6 to 9.2 ppg, also significantly overcompensated.

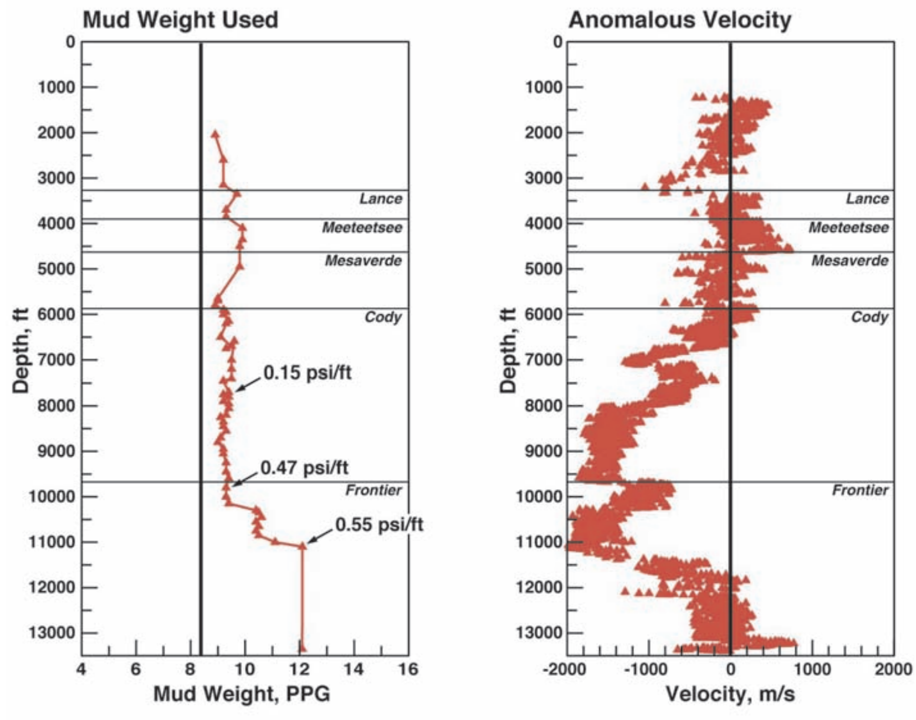


Figure 8. Mud weight and anomalous velocity profiles for a Wind River Basin well. The regional pressure surface boundary is in the Cody Formation at 6300 ft depth. The underpressured zone is probably from 6300 to ~10,000 ft depth. Mud weights used to drill this interval were 8.9 to 9.4 ppg. There is no indication that the upper potion of the anomalously pressured zone is overpressured rather than underpressured. Thus, mud weights used to drill the gas-charged, underpressured section were significantly overcompensated.

1. The rock/fluid systems are gas-charged (i.e., have anomalously slow velocities), so they must be either overpressured or underpressured, as they do not fall on the hydrostatic gradient as a result of the gas charge.
2. If the section being drilled were substantially overpressured, it would have to be drilled with mud weights greater than 8.5-9.0 ppg, otherwise control of the well could be lost.
3. If the section being drilled were underpressured (Figure 7), mud weights of 8.5 to 9.0 ppg would be significantly overcompensated.
4. In the examples shown in Figures 8 and 9, the portion of the section of interest is anomalously slow (i.e., gas-charged) and, thus, anomalously pressured. The mud weights are approximately 9 ppg, yet DSTs suggest underpressuring. If so, the mud weight program utilized in Figures 8 and 9 in the upper portion of the anomalously slow velocity section was grossly overcompensated as this portion of the section was penetrated.

These badly damaged zones still contain a huge gas resource that operators can exploit if they can design effective remediation and recompletion strategies for gas stripper wells and some abandoned wells. Therefore, it is important to design techniques to identify bypassed pay and highly damaged productive zones in RMLB gas stripper wells, because in most of these wells, these zones are characterized by an underpressured rock-fluid system (Figures 6 through 10).

For 45 wells, mud weights, velocity inversion surfaces, anomalous velocity profiles, lithology, resistivity, porosity, pressure tools, gas shows, and production data were evaluated. In every case, for the upper portion of the anomalously slow velocity domain (i.e., gas-charged volume), the mud weights were typically 9 to 10 lb/gal. Thus, if any underpressured rock/fluid systems were present in these wells, they would have been badly damaged during drilling (Figure 10). Figure 1 demonstrates that, in the underpressured portion of the section, there are significant potential sandstones reservoirs. The key question is how significant and widespread are underpressured rock/fluid systems in the Wind River and Greater Green River Basins? If underpressured rock/fluid systems are significant and

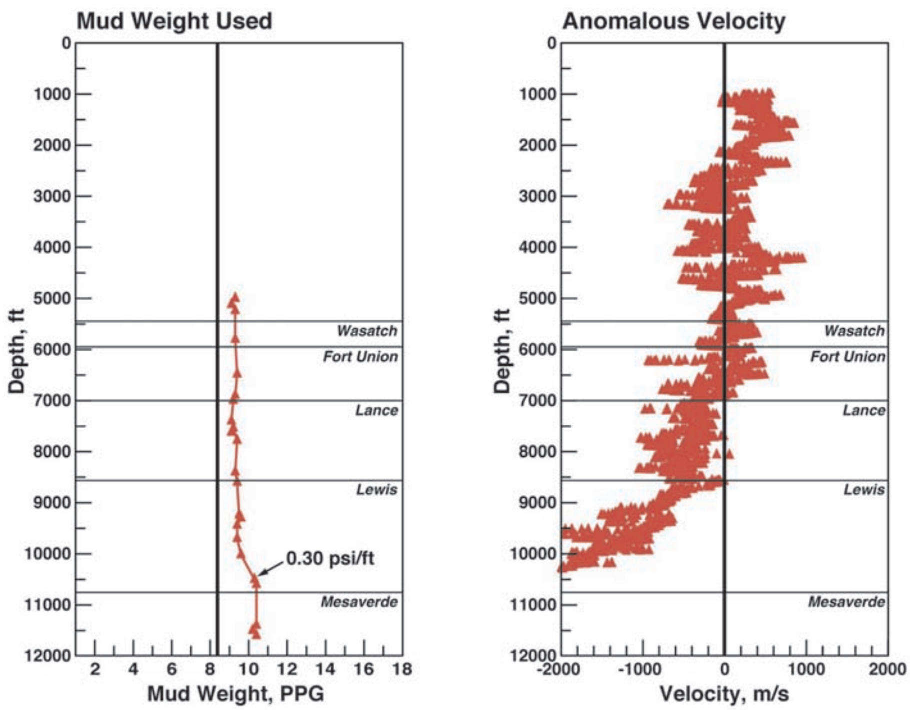


Figure 9. Mud weight profile and anomalous velocity profile for a Washakie Basin, WY well. The regional pressure surface boundary is within the Fort Union Formation at 6500 ft depth. The anomalously pressured zone is from 6500 to DT. Mud weights used to drill this anomalously underpressured interval were 8.9 to 10.3 ppg, again, overcompensated.

widespread, there is huge bypassed gas potential in both existing gas and gas stripper wells.

It is possible to detect significant thicknesses of underpressured, gas-charged sandstone reservoirs in 30 of the 45 wells studied (Table 1); thus, there are large columns of rock/fluid that are underpressured and gas-charged in 30 of the 45 wells studied in the Wind River and Green River basins. Each of the 30 wells in which underpressured, gas-charged reservoirs exist were drilled with 9 to 10 lb/gal mud, or significantly overcompensated mud programs. To determine the magnitude of the resource, the Wind River Basin was chosen for a more detailed regional evaluation.

Wind River Basin

Anomalously Slow Velocity Volumes

Figures 12 and 13 are the *refined* diagrams for the lower Fort Union and Lance Formations, Wind River Basin, illustrating the anomalously slow velocity domains below the regional velocity inversion surface. The regional velocity inversion surface is equivalent to the pressure surface boundary that separates the normally pressured, water-dominated, rock/fluid systems above from anomalously pressured, capillary-dominated rock fluid systems below. The two anomalously slow velocity volumes shown in Figures 12 and 13 are based on approximately 2500 mi of 2-D seismic lines and nearly 200 sonic velocity logs. Thus, the volumes shown in Figures 12 and 13 were constructed from approximately 132,000 velocity/depth profiles. Surdam et al. (1997) have shown that in the Rocky Mountain Laramide Basins (RMLB), the anomalously slow velocity domains typically are anomalously pressured and gas-charged. From this construction (Figures 12 and 13), the anomalously pressured, gas-charged rock/fluid systems in the lower Fort Union and Lance formations can be detected and delineated. Unfortunately, the velocity evaluation is incapable of distinguishing whether the anomalously slow velocity domains are underpressured or overpressured rock/fluid systems. To make a pressure determination for the volumes shown in Figures 12 and 13, it is essential to integrate pressure data into the analysis.

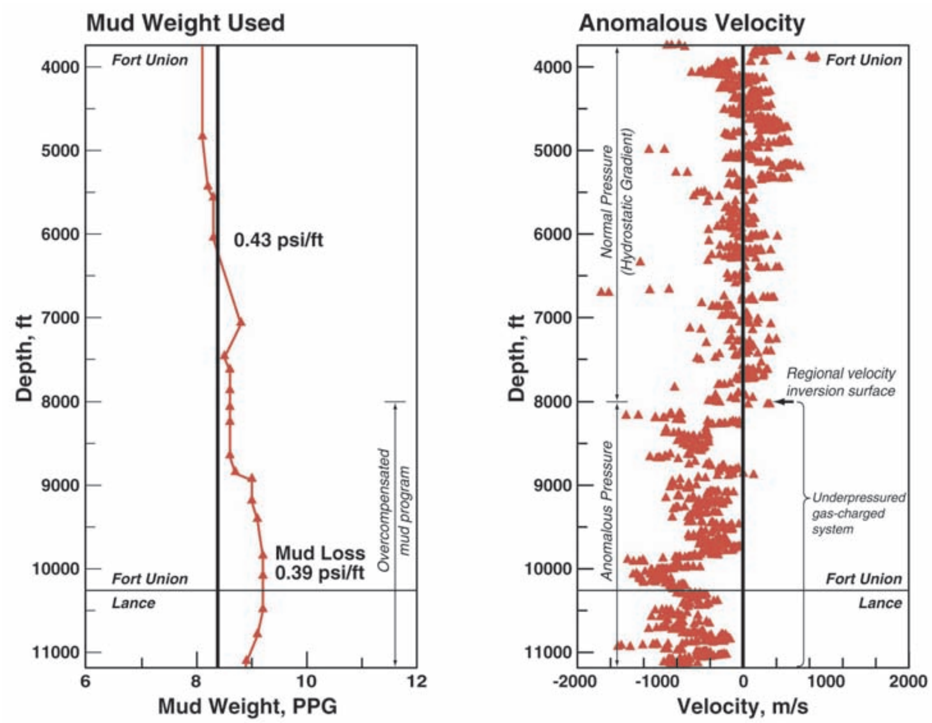


Figure 10. Left: mud-weight profile for a western Wind River Basin well, with available pressure gradients from DSTs. Right: Anomalous velocity profile for the same well. Velocity along the regional normal velocity/depth function falls on the vertical black line; velocities falling left of the vertical black line are anomalously slow and indicate rocks will tend to be gas-charged and anomalously pressured.

Pressure Data

Figures 14A,B and 15A,B are the pressure data for the Fort Union and Lance formations in the Wind River Basin, Wyoming. These Fort Union Formation data were originally from 297 wells and 1212 tests, and the Lance Formation data were from 129 wells and 611 tests. The data shown in Figures 14 and 15 were edited according to the following scheme:

1. For the included tests, both the initial shut-in pressure (ISIP) and final shut-in pressure (FSIP) had to be reported or the test was discarded;
2. The ISIP and FSIP values had to agree within 10% or the test was discarded;
3. All pressure data characterized by gradients less than 0.1 psi/ft (i.e., gas gradient) were eliminated; and
4. All pressure data at depths below 12,000 ft were deleted, because below this depth there is a rapid rise n the percentage of overpressured rock/fluid systems.

This data filtering was done to eliminate unreliable measurements and to isolate and focus on the potential for the existence of underpressured rock/fluid systems in the Wind River Basin. The results from the filtered data show that in the Fort Union tests, 72% of the determined pressures were anomalous (i.e., off of the hydrostatic pressure gradient) and of this group, 78% were underpressured. For the Lance Formation, the data show that 75% of the tests resulted in anomalous pressures (i.e., off of the hydrostatic gradient) and of this group, 86% were underpressured. Thus, substantial evidence exists to indicate that significant portions of both the Fort Union and Lance formations — characterized by anomalous velocities (Figures 12 and 13) — in the Wind River Basin, Wyoming are underpressured.

Regional Pressure Gradient Distribution for the Fort Union and Lance Formations

In order to translate the information shown in Figures 14 and 15 into a regional context and to integrate the results with the anomalous velocity volumes shown in Figures 12 and 13, regional pressure gradient contour maps were constructed for the Fort Union and Lance for-

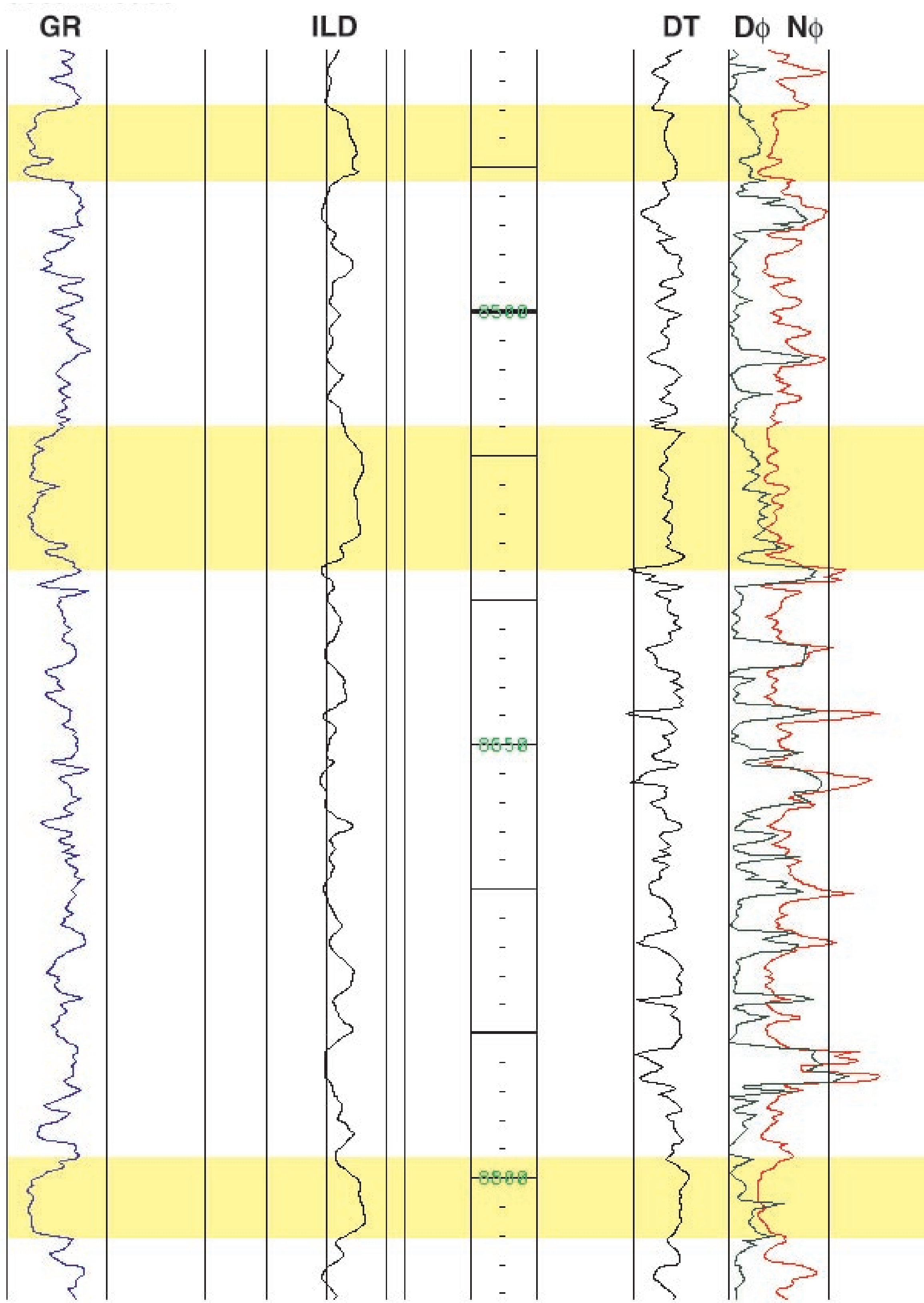


Figure 11. Log suite profiles from a portion (8500-8800 ft) of the well shown in Figure 10. The yellow zones are sandstone intervals that, based on log characteristics, are gas-charged and, from Figure 10, are underpressured.

mations (Figures 16 and 17, respectively). Figures 16 and 17 illustrate that within the Fort Union and Lance formations, there are substantial portions of the rock fluid systems that are underpressured (i.e., pressure gradients <0.4 psi/ft). Most importantly, the underpressured portions of the rock/fluid system are regionally continuous in a lateral sense, and are not broken up into small, discontented pockets (Figures 16 and 17).

Problems Plaguing the Exploitation of These Underpressured Gas Resources

Underpressured gas resources in the Wind River Basin and in the other RMLB in Wyoming are being overlooked as significant exploration targets. At best, they are treated as incidental targets encountered while drilling to popular deeper overpressured targets. As a result, the gas-charged, underpressured Fort Union and Lance rock/fluid systems are typically drilled with 9-10 ppg muds (i.e., compensated at pressure gradients of 0.47 to 0.52 psi/ft), leading to the numerous drilling problems plaguing operators while drilling through the underpressured rock/fluid systems. The typical response to these problems is to increase mud weight insuring an increase in the severity of problems such as lost circulation, questionable mud/gas log interpretations, sloughing shales, questionable open hole evaluations, and formation damage.

To our knowledge, there has never been a well drilled in the Wind River Basin solely to test an underpressured target. As a consequence, the huge underpressured gas-charged section in the Wind River Basin at best yields stripper well gas production from severely damaged reservoirs, and at worst the pay zone is completely bypassed. This is one reason why Wyoming leads the Nation in the increase of gas stripper wells (1909 gas stripper wells in 1999

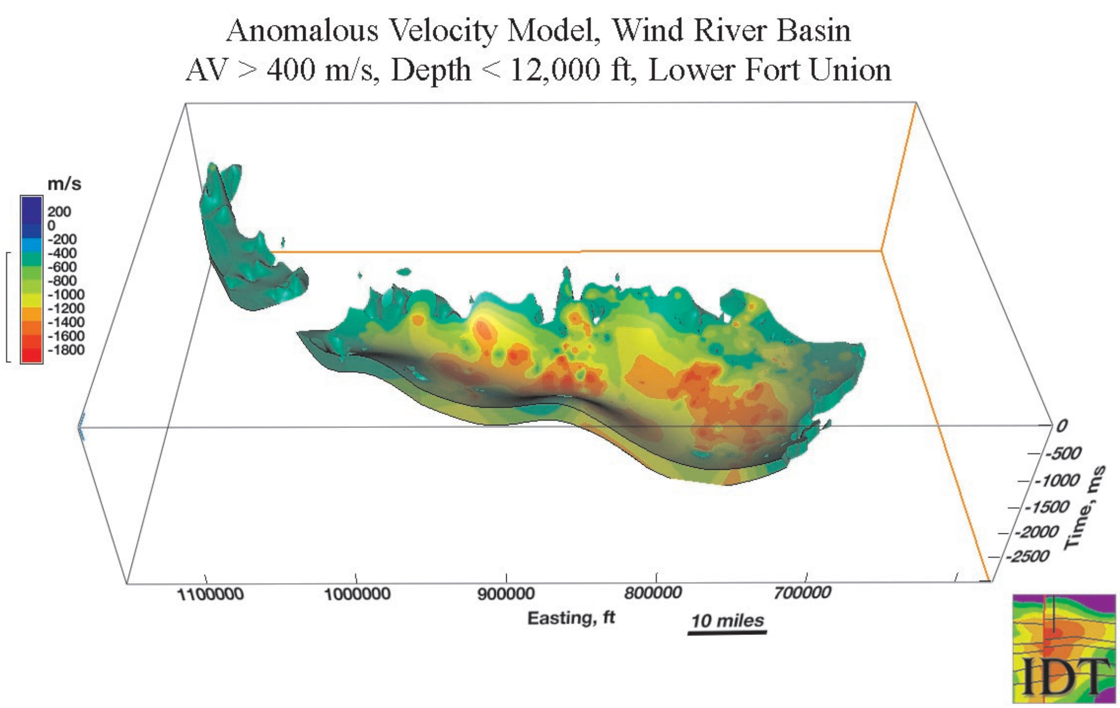


Figure 12. Anomalous velocity model for the Fort Union Formation, Wind River Basin, Wyoming. The normally pressured rock/fluid systems (which plot on the regional hydrostatic gradient) have been stripped off the volume. Only anomalously pressured, gas-charged rock/fluid systems are shown. The anomalous velocity values are derived by removing the ideal regional velocity/depth function from the observed velocity; a minus sign indicates that the value falls below (i.e., slower velocity), or is less than what would be predicted at that point by the ideal regional velocity/depth function. The view in this figure is to the south.

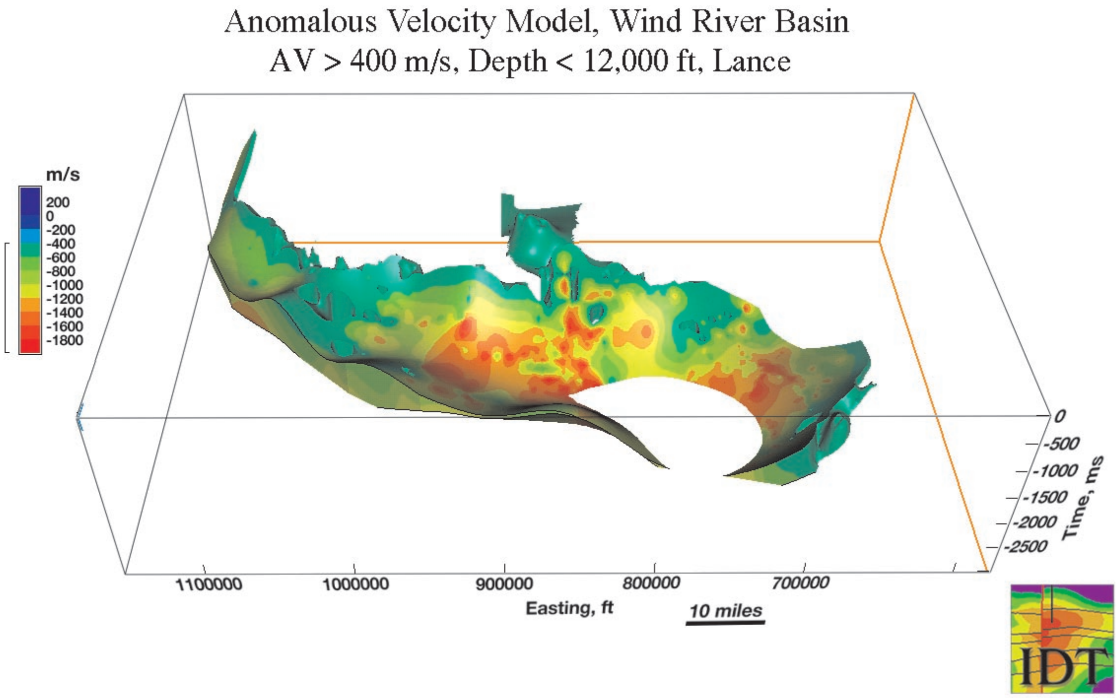


Figure 13. Anomalous velocity model for the Lance Fm., Wind River Basin, WY. Normally pressured rock/fluid systems (which plot on the regional hydrostatic gradient) are stripped off the volume so that only anomalously pressured, gas-charged rock/fluid systems are shown. The anomalous velocity values are derived by removing the ideal regional velocity/depth function from the observed velocity; a minus sign indicates that the value falls below (i.e., slower velocity), or is less than what would be predicted at that point by the ideal regional velocity/depth function. The view is to the south.

and 10,321 gas stripper wells in 2001). In order to exploit this underpressured energy resource in the Wind River Basin of Wyoming and in the other RMLB, operators must recognize the magnitude of this gas resource, and then must treat underpressured gas prospects as priority targets, instead of incidental targets encountered while drilling to traditional deeper overpressured gas resources. Ironically, the largest gas fields in Rocky Mountain basins are underpressured (Elmworth, Milk River, and Hoadley fields in the Alberta Basin and the composite fields in the Sand Juan Basin, New Mexico), yet the possibility and potential of underpressured gas resources in the RMLB of Wyoming is ignored. The work accomplished by the research group at IDT and supported by the DOE Stripper Well Consortium has given operators in the RMLB the diagnostic tools to recognize underpressured, gas-charged rock/fluid systems prior to drilling.

Diagnostic Techniques

Badly damaged zones can still contain a huge gas resource that operators can exploit if they can design effective remediation and recompletion strategies or select new completion zones for gas stripper wells and some abandoned wells. Therefore, it is important to design techniques to identify bypassed pay and highly damaged productive zones in RMLB gas stripper wells, because in most of these wells, these zones are characterized by an underpressured rock-fluid system.

The following diagnostic steps are suggested in order to determine the presence of underpressured rock/fluid systems in the RMLB:

1. First, the regional normal velocity/depth trend is removed from the observed sonic velocity/depth profile. The results of this operation are two-fold: (1) isolation of anomalously slow sonic velocities and (2) defini-

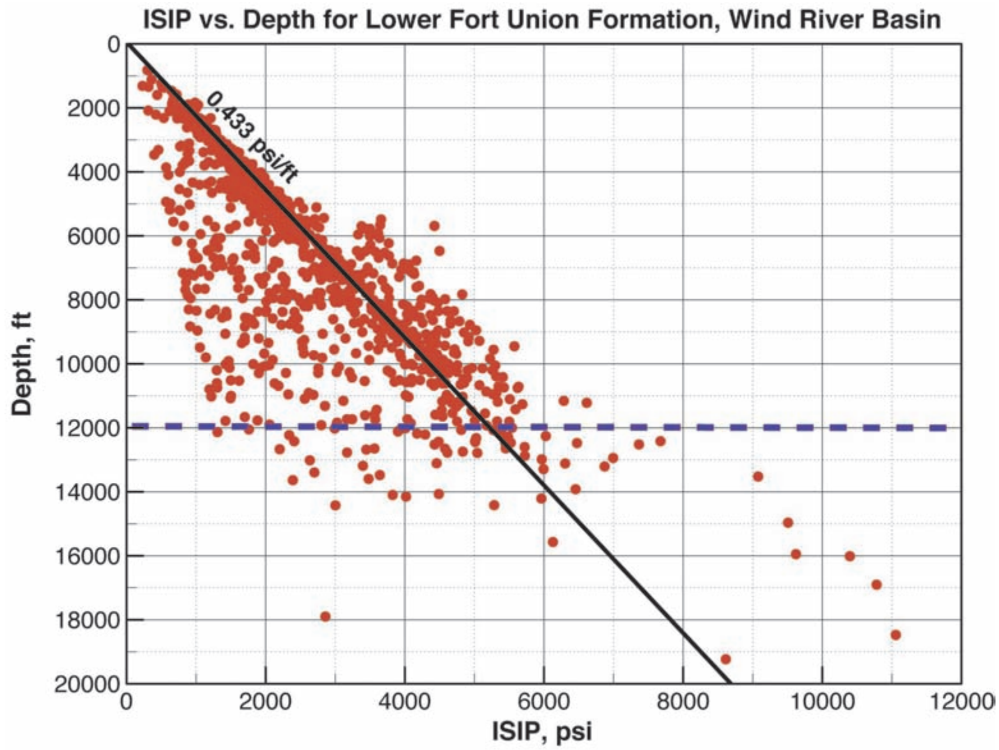


Figure 14A. Plot of the edited (see text) plot of the ISIP vs. depth for the Fort Union Formation, Wind River Basin, Wyoming.

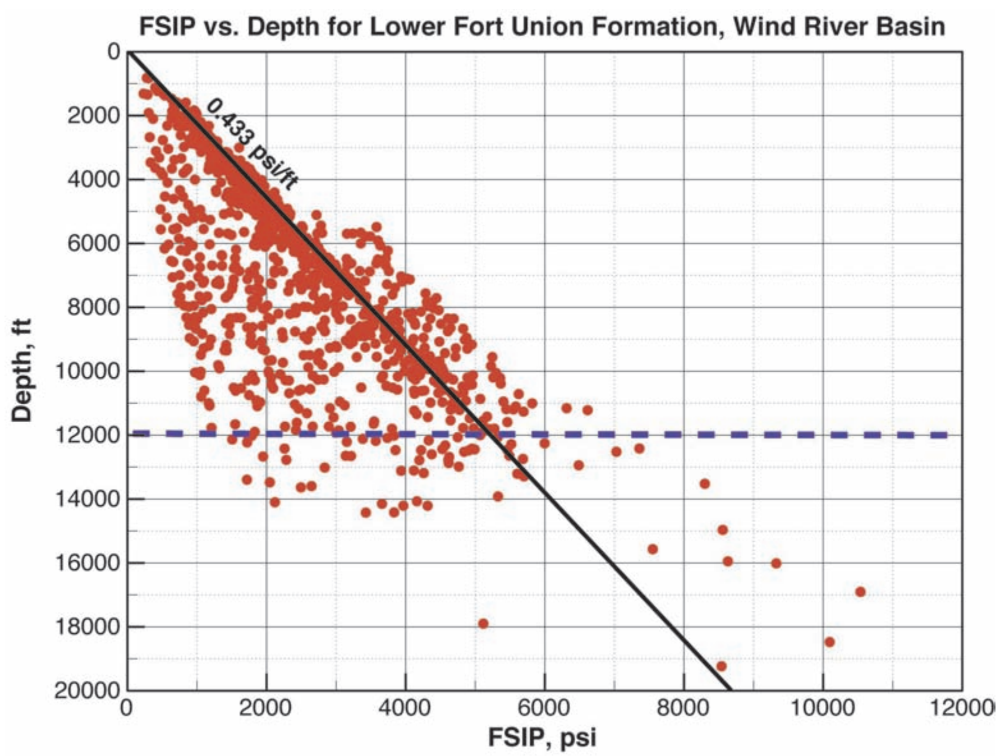


Figure 14B. Plot of the edited (see text) plot of the FSIP vs. depth for the Fort Union Formation, Wind River Basin, Wyoming.

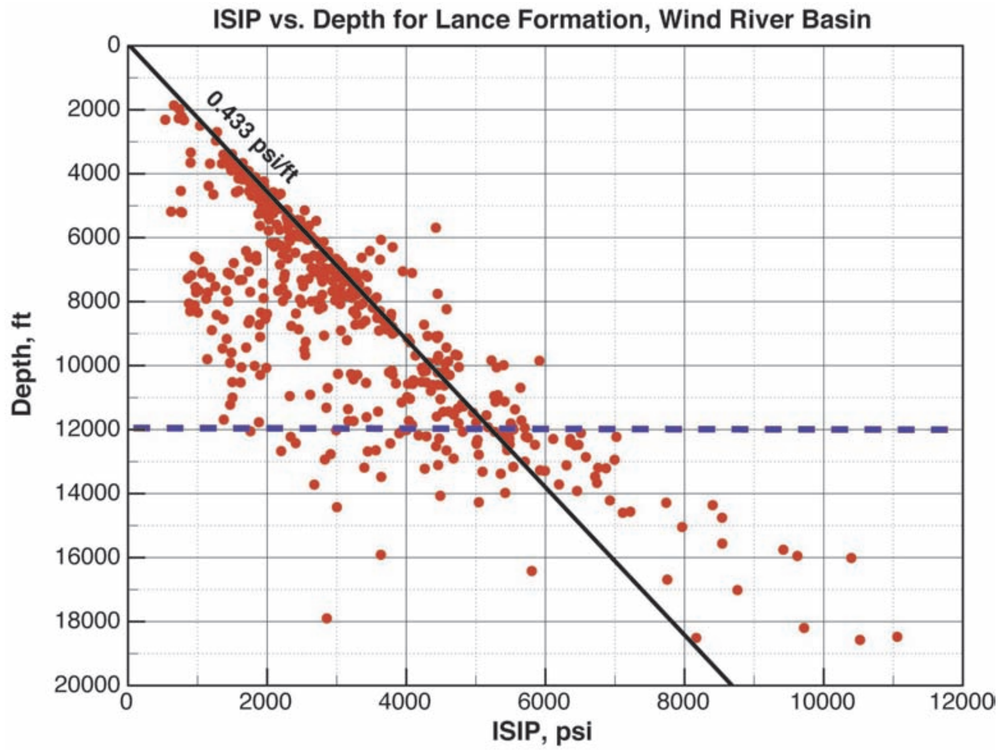


Figure 15A. Plot of the edited (see text) plot of the ISIP vs. depth for the Lance Formation, Wind River Basin, Wyoming.

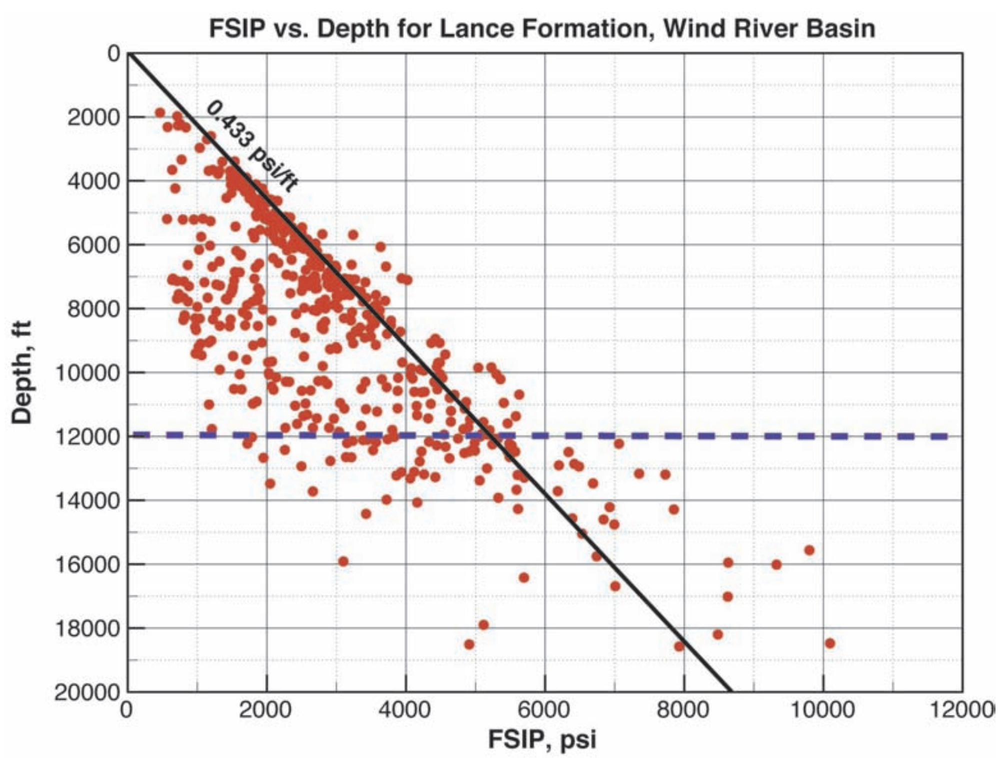


Figure 15B. Plot of the edited (see text) plot of the FSIP vs. depth for the Lance Formation, Wind River Basin, Wyoming.

tion of the regional velocity inversion surface. The isolated anomalously slow velocity domains beneath the regional velocity inversion surface in the RMLB are gas-charged (Surdam, 1997; Surdam, 2001 a,b). Previous work indicates that the regional velocity inversion surface is the boundary between normally pressured rock-fluid systems above and anomalously pressured, gas-charged rock-fluid systems below.

2. Next, the pressure data, derived from drill stem tests and other pressure indicators, are integrated with the anomalous velocity profiles. This integration allows underpressured and overpressured portions of the anomalously slow velocity domain to be delineated.
3. Step three is the evaluation of the distribution of potential reservoir sandstones within the section characterized by anomalously slow velocities and underpressuring. Typically, the relatively thick sandstones within the underpressured, anomalously slow velocity domain are characterized by low gamma ray, high resistivity, high density porosity, and low neutron porosity. These log characteristics are consistent with the interpretation that these sandstones are gas-charged. Where possible, information concerning background gas, gas shows, and gas flows is integrated into the evaluation.

This evaluation scheme could be used to determine the presence or absence of underpressured, gas-charged potential reservoir sandstones. From this sequence of steps, it is possible to detect significant thicknesses of underpressured, gas-charged sandstone reservoirs. In this study, every well that was diagnosed with underpressured, gas-charged sections had been drilled with 9 to 10 lb/gal mud.

This zone of underpressured, gas-charged, rock/fluid has been unrecognized in many of the RMLB because, relative to the San Juan and Alberta basins, the zone tends to be thin in most other basins (Figure 18). In the San Juan and Alberta basins, operators drill from normally pressured sequences, across the regional velocity inversion surface, into a very thick and productive underpressured section (Figure 18; right

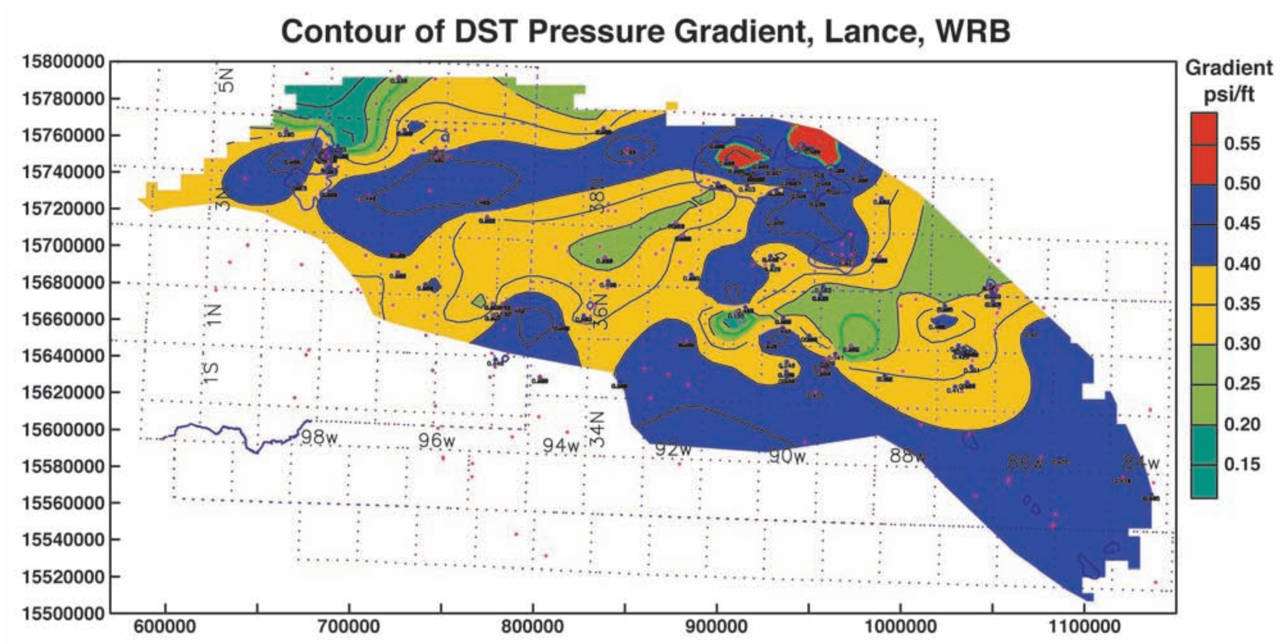


Figure 16. Contour map of the pressure gradients within the Lance Formation, Wind River Basin. Yellow/green areas depict the underpressured rock/fluid systems; red areas indicate overpressured rock/fluid systems; blue areas indicate normally pressured rock/fluid systems. The view in this figure is to the north.

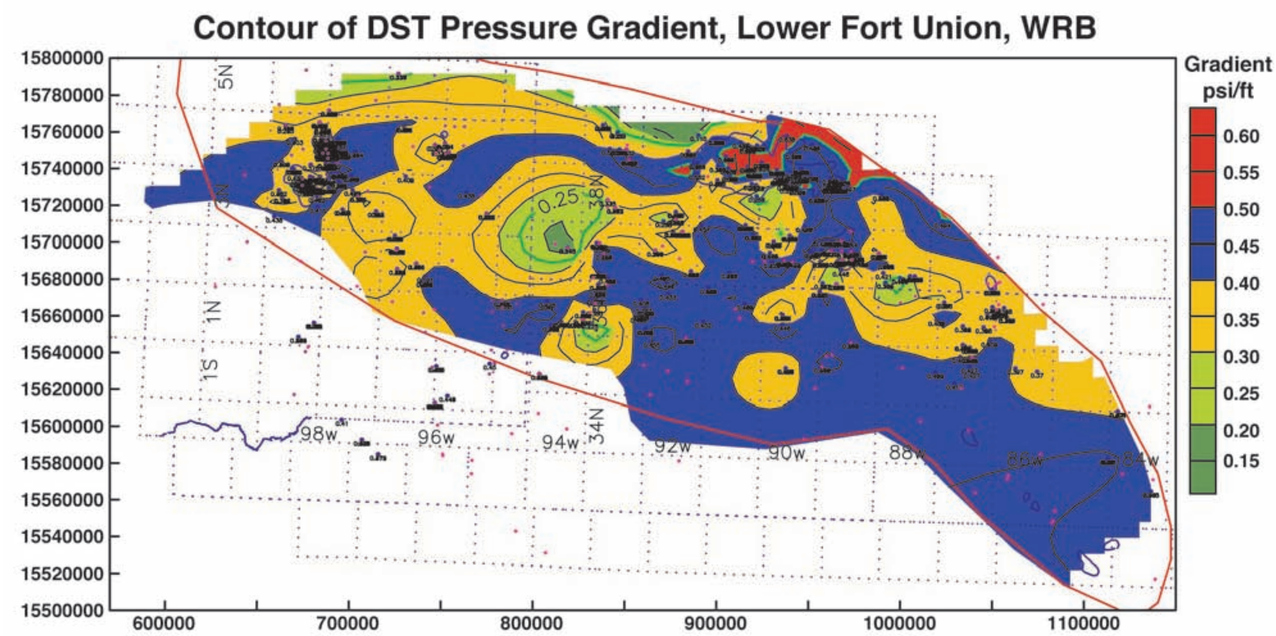


Figure 17. Contour map of the pressure gradients within the Fort Union Formation, Wind River Basin. Yellow/green areas depict the underpressured rock/fluid systems; red areas indicate overpressured rock/fluid systems; blue areas indicate normally pressured rock/fluid systems. The view in this figure is to the north.

side of diagram). In contrast, in the other RMLB, operators drill from normally pressured sections, across the regional velocity inversion surface, into a relatively thin and historically unrecognized underpressured, gas-charged section, *then* into a thick, overpressured productive zone (Figure 18; middle of diagram). Historically, the driller's primary concern has been to prepare for the transition from normal pressure to overpressure. Consequently, most wells, excluding the San Juan and Alberta basins, have been drilled with significantly overcompensated mud programs.

Conclusions

It is concluded that in the Wind River and Green River basins, significant rock/fluid columns occur that are underpressured and gas-charged. Each of the evaluated wells were drilled with significantly overcompensated mud weight programs. Thus, there is high potential that serious damage occurred during the drilling of the underpressured, gas-charged sandstones, or that gas pay was bypassed. The diagnostic steps outlined in this report will greatly assist operators in predicting the distribution of underpressured, gas-charged rock/fluid sections.

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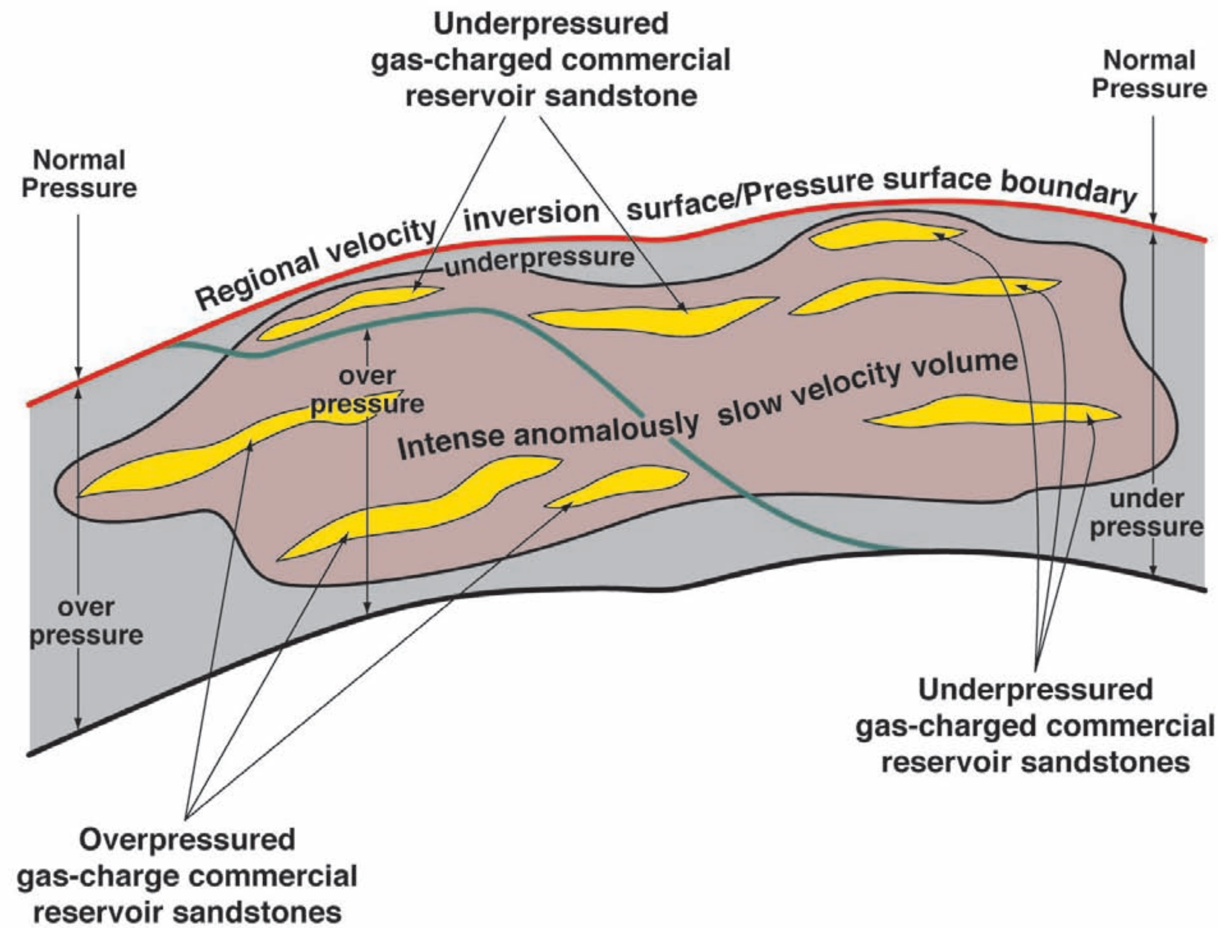

Figure 18. Schematic diagram illustrating the differences in pressure regimes in basins like the San Juan and Alberta basins, as compared to basins like the Wind River and Green River basins. In the San Juan and Alberta basins, the pressure transition is from normal pressure to a thick, underpressured, gas-charged and productive section (right side of diagram). In contrast, in RMLB like the Wind River and Green River basins, the transition is from normal pressure to a relatively thin, underpressured, gas-charged section, underlain by a relatively thick, overpressured, gas-charged and productive section (left side of diagram).

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Reservoir Characterization of the Wileyville Oil Field

Final Technical Report

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DISCLAIMER

ABSTRACT

The Wileyville oil field, currently owned and operated by East Resources of Wexford, PA, was discovered in 1900. From 1900 to 1905, the productive and geographic limits of the Upper Devonian Gordon sandstone reservoir in the field were established. Secondary recovery by waterflooding began in 1997; the injection of more than 5 million barrels of water has only recently produced an increase in oil production.

Our study set out to determine the cause of this lag between injection and production by characterizing and evaluating the heterogeneity of the Gordon reservoir. The process of reservoir characterization consisted of a number of phases including: an analysis of the drilling and production history of the field and an investigation of the lithology, petrography, and petrophysics of the reservoir. Additionally, an assessment of uphole hydrocarbon potential was undertaken.

The short time period (six years) during which Wileyville became established as an oil field was the first indicator of relatively low reservoir heterogeneity. Work with core and geophysical logs from the field allowed the identification of the pay sandstone within the reservoir. Termed the *Featureless* Sandstone Lithofacies, this poorly cemented, highly bioturbated, porous (mean porosity greater than 16%) and permeable (mean permeability greater than 90 mD) siliciclastic material is situated in the middle of the Gordon interval. Continuous and well-connected in the southern half of the field, strata of the Featureless Sandstone Lithofacies thin to the north and become interbedded with impermeable shales and tightly cemented sandstones. This disparity in reservoir heterogeneity between the two halves of the field is mirrored in the difference in initial potential (IP) values between south (low heterogeneity - high IP's) and north (higher heterogeneity – lower IP's).

There appears to be potential for the production of additional hydrocarbons in the form of natural gas uphole from the Gordon interval in Wileyville. Sandstones in the Pennsylvanian Allegheny Formation and Pottsville Group are gas-prone in the area. Investigation of the coal-bed methane potential of coals in the Allegheny Formation and Monongahela Group estimates more than 35 Bcf of gas-in-place for these units. In addition, the de-watering of these coals to establish coal-bed methane production could provide an important source of injectable water for ongoing water flood operations.

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INTRODUCTION

Fields in the Appalachian basin have produced oil for over 140 years from sandstones within Upper Devonian rocks. These mature fields are characterized by thin pay zones with high initial open flows that declined over time, leaving 70-80 percent of the original oil in place. The Gordon and Gordon Stray sandstones, deposited in nearshore and onshore environments, have produced oil from about two dozen fields in southwestern Pennsylvania and northern West Virginia. Secondary recovery projects have been implemented in several of these fields, often with mixed success even after a significant outlay of time and expense.

The Wileyville field in northern West Virginia is the location of a line-drive, water-injection project that has only started producing oil; approximately 5 million gallons of water have been injected since February 1997. Frequent causes of injectivity problems include a poor understanding of the lithologic relationships within a field, the presence of discrete compartments or baffles to flow within the reservoir, or the existence of *thief* zones in communication with water injection wells.

The goal of the this study was to establish the nature and degree of heterogeneity within the Gordon interval in Wileyville field through reservoir characterization. The product is a three-dimensional model of depositional and lithologic units within the field. Analysis of historical drilling trends, measurement of permeability, stratigraphic correlation, definition of lithofacies and electrofacies, and identification of depositional units allowed the research team to infer compartments within the field, and to identify stratigraphic and geographic trends in these compartments.

Knowledge of reservoir architecture allows one to more efficiently and effectively design a waterflood of appropriate geometry, to locate injection wells, and to site new production wells.

EXECUTIVE SUMMARY

The Wileyville oil field in northern West Virginia is the location of a line-drive water-injection project that has only recently started producing oil; 5 million gallons of water have been injected since February 1997. Frequent causes of injectivity problems include a poor understanding of the lithologic relationships within a field, the presence of discrete compartments or baffles to flow within the reservoir, or the existence of *thief* zones in communication with water injection wells.

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From 1900 to 1905, the entire producing reservoir in Wileyville was delineated by the drilling process. Based on our previous experiences with reservoir characterization of siliciclastic reservoirs in West Virginia, we believe that this pattern of completions is indicative of a relatively low degree of reservoir heterogeneity.

Cores from two wells in the Wileyville oil field were examined and described. Lithofacies were defined based on apparent grain size, variability in grain size within beds (sorting), presence or absence of laminations, evidence of bioturbation, lithologic textures, and presence or absence of crossbedding. Lithologic units were then compared with geophysical logs to determine log characteristics corresponding with each lithofacies. Information obtained from East Resources included data used to contour initial potential for comparison with maps of electrofacies and lithofacies.

Five lithofacies occur in the Gordon interval and can be recognized in geophysical logs. The Featureless Sandstone lithofacies with a density around 2.3 g/cm^3 comprises the primary reservoir for the field. In the southern part of the Wileyville field, the reservoir sandstone is continuous and probably well-connected. In the northern part of the field, featureless sandstones thin to almost zero thickness, suggesting that the northern part of the study area is not well-suited to waterflooding. Maps of initial potential shows spatial trends consistent with observed distribution of the featureless sandstone.

Two cores received from East Resources were examined systematically for lithologic and sedimentologic features, and sampled for permeability with a TEMCO MP-401 minipermeameter. Prepared thin sections were examined for grain size, mineralogy, and cementation.

The Featureless Sandstone lithofacies is predominantly quartz, fine-grained, well-sorted, and subangular. These sandstones are poorly cemented and highly permeable, making them good reservoir rock. Elongated quartz grains that have been rotated 90º to bedding indicate bioturbation. Early calcite cementation localized in bioturbated sediment formed barriers to interstratal migration of fluids. Seals between adjacent sedimentary layers probably reduced or prevented late-stage cementation and helped preserve initial permeability. Where bioturbation was more intense, the interstratal seal was more effective in preserving permeability. The Featureless Sandstone has the highest permeability of the five lithofacies, with a mean value greater than 90 mD.

Minipermeameter permeability values from Wileyville cores generally exceed whole core values but are less than core plug values for k_{hmax}.

Cements in the Gordon, in order of appearance, include calcite, clays, quartz overgrowths, and siderite. Combined primary and secondary porosity values in the Gordon range from 3% to 17% with a mean value of 9%. Secondary porosity is primarily intragranular and is often associated with the alteration or dissolution of feldspars.

Electrofacies in two reference wells were established by cluster analysis of depth, gamma ray, density, permeability, and grain size data. It was found that four electrofacies based on a linear combination of density and scaled gamma ray best matched previous stratigraphic correlations. Discriminant function coefficients were used to assign each interval of the available geophysical logs to one of these four electrofacies.

Four electrofacies were identified in the Gordon interval. Electrofacies 4 corresponds with the pay sandstone in the Gordon, a combination of Featureless Sandstone and minor Conglomeratic Sandstone lithofacies. A vertical electrofacies cross-section along the long axis of the field suggests that Electrofacies 4 is generally restricted to the middle of the Gordon interval. The Gordon in the Wileyville field is observed to deepen to the northeast along the plunge of structure. No serious lateral impediments to flow are visible in the cross section. However, a gap in well control is present in the southern portion of the field and this gap corresponds to a distinct break in IP values in the area.

Previous studies of coal bed methane occurrences and major gas plays in the region of the Wileyville field were examined to assess uphole potential in this field. The best uphole potential appears to be in the shallowest plays, the Allegheny and Pottsville sandstones and associated coals, and in developing the coal-bed methane potential of the Allegheny Formation and lower Monongahela Group. Total gas in place for two coals in the lower Monongahela and six coals in the Allegheny, is approximately 35.74 Bcf for the area encompassed by the Wileyville oil field. Coal beds present above the Gordon oil reservoir are expected to be water-filled in this field. In de-watering the coals to establish coal-bed methane production, an important source of water for the continuation of the Wileyville waterflood in the Gordon oil reservoir could be developed.

HISTORY AND GEOLOGIC SETTING OF THE WILEYVILLE FIELD

History

The Wileyville oil field was discovered Wetzel County, WV in 1900 (Figure 1). To investigate the development history of the field and to get a preliminary assessment of heterogeneity within the field, completion-location analysis (McDowell and others, 1992) was undertaken. The completion dates for all producing wells in the field were subjected to spectral analysis (Figure 1) to see how well completions were distributed in time. Next, the geographic locations of all producing wells were plotted within the field in order of each well's date of completion.

We have noted (McDowell and others, 1992; McDowell and others, 1993; Hohn and McDowell, 1993; Hohn and others, 1993a and 1993b; Ameri and others, 2001; Matchen and others, 2001) that, in general, the number of completions of producing wells clustered in the same geographic area within the same short interval of time (five to ten years) corresponds in a qualitative manner to the heterogeneity within the reservoir. Examination of Figure 1 suggest the presence of only three clusters of completions and only one of them (1899-1905) includes more than two wells. Figure 2 shows the locations of producing wells completed in each of the years from 1900 to 1905. During this six year time span, the entire producing reservoir in Wileyville was delineated by the drilling process. Discovery started in the southern portion of the field and proceeded rapidly to the northeast so that, by 1902, the linear nature of the field and its longest dimension had been established. Based on our previous experiences with reservoir characterization of siliciclastic reservoirs in West Virginia, we believe that this pattern of completions is indicative of a relatively low degree of reservoir heterogeneity. Certainly, heterogeneity is lower than that observed in either the Mississippian Big Injun reservoir in the Granny Creek or Rock Creek fields and lower than that observed in the Devonian Gordon reservoir in the Jacksonburg-Stringtown field.

Geological Setting

Structure

The waterflood project within the Wileyville oil field is situated along a small anticline between the larger Nineveh Syncline and the Littleton Anticline (Figure 3). The remaining portion of the field wraps around the anticline to the north and west (Cardwell and Avary, 1982); this portion of the field was not developed for waterflood. Within the project area, the Gordon dips northward following the plunge of the anticline. This dip may be as steep as 25° and appears to be consistent, suggesting that there is no structural compartmentalization within the project area.

Stratigraphy

Gordon sandstones are part of the thick, Upper Devonian sedimentary section. In West Virginia, the outcrop equivalent is the Hampshire Formation (Figure 4). Sediment composition varies considerably between non-marine red shales and fluvial sandstones of the Hampshire Formation in the eastern outcrop belt of West Virginia, Maryland, and Pennsylvania, to distal marine shales of the Ohio Shale in the western outcrop belt of Kentucky and Ohio. Intervening sedimentary rocks grade between these two extremes, containing at different locations, fluvial, shoreline, or shelf sandstones and shales; the Gordon lies within the shoreline portion of this spectrum. In general, marine content decreases to the east.

In the Jacksonburg-Stringtown oil field, the Gordon is composed of four parasequences, three of which contain lithofacies associated with the producing reservoir. The fourth parasequence, located above the primary reservoir is comprised of bioturbated sandstones and shales. Similar strata are encountered in Wileyville and serve as a marker for stratigraphic correlation. North of the Jacksonburg-Stringtown field, the lower two parasequences, both of which contain pay sandstones, grade into shale. Correlation of the Gordon to the north shows the sandier portion of the lowermost parasequence pinching out, reducing the number of definable parasequences in Wileyville to three, one of which contains oil producing reservoir. This correlation suggests that there is a single primary reservoir in the Wileyville field which can, perhaps, be treated as a single compartment for development purposes (Figure 5).

LITHOFACIES, STRATIGRAPHIC FRAMEWORK, AND PRODUCTION

Methodology

Cores from two wells in the Wileyville oil field (Figure 6) were examined and described. Lithofacies were defined from apparent grain size, variability in grain size within beds (sorting), presence or absence of laminations, evidence of bioturbation, lithologic texture, and presence or absence of crossbedding. Lithologic units were then compared with geophysical logs to determine log characteristics corresponding with each lithofacies. A spreadsheet of information obtained from East Resources included initial potential production data from several sources. Wells differed in the number of sources of data. Graphs of reported values showed data from the two main sources to be significantly positively correlated; both sources were used to contour initial potential for comparison with maps of electrofacies and lithofacies.

Results and Discussion

Lithofacies

Five lithofacies can be recognized: Featureless sandstone (*Fss*), Laminated sandstone (*Lss*), Conglomeratic sandstone (*Css*), Shale (*Sh*) and Heterolithic bioturbated (*Hb*).

Each lithofacies is relatively distinctive in core and has a recognizable pattern on geophysical logs. The three sandstone lithofacies (*Fss*, *Lss*, and *Css*) comprise most of the Gordon interval. Where present, the *Sh* Lithofacies is useful for field-scale correlation. The *Hb* Lithofacies lies above the reservoir and is useful for paleoenvironmental interpretations and correlation.

Shale (*Sh*) is dark gray and laminated. Thin bands of siderite are present in some samples. The thickest shale beds are found in the lower part of the Gordon and are known only from log, as core was not available for the lowest interval.

Shale in core may also be interbedded with fine-grained sandstone and shale, which is also often bioturbated. This is the Heterolithic bioturbated (*Hb*) Lithofacies commonly found in the uppermost parasequence of the Gordon interval and correlative from the Jacksonburg-Stringtown oil field to Wileyville. Bioturbation is not as obvious in the Wileyville cores; some horizontal and vertical burrows are present (Figure 7).

Featureless sandstones (*Fss*) are fine- to very fine-grained, very well-sorted, and contain few recognizable sedimentary structures (Figure 8). Faint horizontal laminae and isolated quartz pebbles are observed infrequently. Occasionally, single-pebble layers are present.

Laminated sandstones (*Lss*) are fine- to very fine-grained, very well-sorted, and contain a wide variety of sedimentary structures. Horizontal laminations and low-angle crossbedding (Figure 9) are common. In some cases, crossbedding is bidirectional, perhaps herringbone. Sedimentary structures are clearest when clay laminae are present. Single-grain, quartz pebble layers are limited to a few per core. Bioturbation is rare; when present, it is often in the form of large single burrows.

Conglomeratic sandstone (*Css*) displays a bimodal grain size (Figure 10) ranging from fine- to very fine-grained sand to pebbles. There is little material of intermediate grain size. Texture varies from matrix-supported to clast-supported. Scour surfaces are common and many conglomerate beds appear to be lags deposited upon such surfaces. Other sedimentary structures include: low-angle, bi- and unidirectional crossbedding, high-angle (up to 30^o) crossbedding, reverse grading, rare ripple beds, and shale rip-up clasts.

Because there are many more wireline logs (27) for the field than cores, differentiation of lithofacies in log is critical to characterization of the reservoir. In core, lithofacies *Lss* and *Css* are denser than lithofacies *Fss*. This variation is obvious on wireline logs as well (Figures 11 and 12). On logs, lithofacies *Lss* and *Css* have a density of around 2.5 g/cm^3, whereas *Fss* sandstones have a density of around 2.3 g/cm^3. Gamma ray values are about the same for all three lithofacies, although the *Css* lithofacies often has the lowest gamma ray values. The sharp change in density values for *Fss* make the lithofacies very easy to distinguish as the primary reservoir for the field. Permeability profiles constructed using minipermeameter data (see Figures 11 and 12) show a similar relationship – the highest permeabilities are for *Fss* sandstones. Within the Gordon as a whole, permeabilities range from less than 25 mD to well over 100 mD.

Lithofacies *Hb* has the most variable log signature. In Wileyville, log signatures for this lithofacies display both very low and very high gamma ray and density values. This reflects the heterogeneous lithology and bioturbated nature of the Lithofacies. It comprises no productive reservoir material but has proven useful as a stratigraphic marker.

Stratigraphic Framework

Within the waterflood project area in Wileyville, the Gordon sandstone consists of three parasequences, only one of which contains reservoir-quality sandstone. An isopach of the total Gordon thickness within the waterflood project shows that the Gordon maintains a consistent thickness throughout the project area (Figure 13). The distribution of lithofacies *Fss* within the Gordon (Figure 14) is not as consistent. In the southern part of the waterflood project, the distribution of lithofacies *Fss* is consistent and probably well-connected. However, in the northern part of the project, the *Fss* compartment thins to almost zero thickness, suggesting that the northern part of the study area is less suitable for waterflooding. The same conclusions can be drawn from stratigraphic cross sections through the field (Figures 15, 16, and 17). The southern portion has a consistently thick, well-connected reservoir, whereas the northern part of the project shows a thin, discontinuous reservoir.

Initial Potential

The contour map of oil initial potentials shows that the southern half of the field has higher values than the northern half (Figure 18). The spatial pattern of initial potentials in the northern half is irregular, consistent with the presence of several reservoir compartments in this part of the field. Overall, there is a suggestion of poor communication between the two halves of the field, consistent with the stratigraphic model.

PETROGRAPHY AND PETROPHYSICS

Methodology

Two cores (L. E. Dulaney 10 and L. S. Hoyt 100) were available from the Gordon interval in the Wileyville field. Cores were received from East Resources already split and were examined and described by WVGES personnel. Lithologic and sedimentologic features were recorded in graphical log format (see Figures 11 and 12). Following lithologic description, permeability was sampled at an 0.25’ spacing using a TEMCO MP-401 minipermeameter. Additional permeability samples were taken adjacent to core locations from which 1” diameter plugs had been removed. Permeability data have been added to lithologic logs (see Figures 11 and 12). Based on sedimentological features observed in core and on core permeability values, representative intervals of interest were selected in each core and a total of thirty petrographic thin sections were prepared. Blue epoxy was used to impregnate thin section materials to help in the identification of porosity.

Grain size was assessed in each thin section by the examination and measurement of fifty grains per slide; this was increased to fifty grains in each size fraction when a bimodal grain distribution was present. Grain mineralogy was determined by the examination, identification, and classification of 300 grains in each slide. Mineralogic categories included: Monocrystalline Quartz, Polycrystalline Quartz, Secondary Quartz (as cement), Feldspar, Primary Porosity (intergranular), Secondary Porosity (primarily intragranular), Phyllosilicates, Opaque minerals, Clay (primarily as cement), and *Other* (a catch-all category for rock fragments, fossil fragments, heavy minerals, and other materials). The results of grain size analyses were reported in millimeters and in *phi* units (Krumbein, 1934); the results of mineralogic analyses were reported in percent (see Table 1a).

Thin sections were given a final examination to gain information on cementation history and to select individual slides that were particularly illustrative of typical or unusual features of the Gordon sandstone. Sections were imaged using a Pixera 150es™ digital camera attached to a polarizing petrographic microscope. TIF colour images were converted to JPG format which were then imported into Microsoft PowerPoint™ to produce illustrations for this report.

Results and Discussion

Siderite in clasts (Figure 19a), in mineralized zones (sideritic *fronts* – Figure 19b), and as cement (Figure 20a); rounded quartz pebbles (Figure 20b) and single pebble layers (Figure 21a); and plant debris (Figure 21b) have all been noted in the both the Mississippian Big Injun (Hohn and others, 1993a and 1993b) and the Devonian Gordon (Ameri and others, 2001) sandstones in previous reservoir characterization studies undertaken by the WVGES. The Gordon within the Wileyville field contains similar sedimentologic components.

Based on thin section analyses (Table 1a), the Gordon sandstone in the Wileyville field can be characterized as a fine-grained quartz sandstone, whose grains are generally well-sorted, although distinctive bimodal grain distributions comprising fine to very fine quartz sand and quartz pebbles are also typical (Figure 22a). Feldspar (a mixture of potassium and plagioclase feldspar - Figure 22b) is the most common secondary grain mineral but generally makes up less than 5% grain mineralogy compared to 66% for all types of quartz grains. Shale, siltstone, and sandstone (Figure 23a), and chert (Figure 23b) rock fragments represent an additional 6% of the grains.

Cements in the Gordon, in order of appearance, include calcite (Figure 24a), clays, quartz overgrowths, and siderite. Combined primary and secondary porosity values in the Gordon range from 3% to 17% with a mean value of 9%. Secondary porosity is primarily intragranular (Figure 24b) and is often associated with the alteration or dissolution of feldspars (Figure 25a). Examination and comparison to thin section analyses for the Gordon sandstone in the Jacksonburg-Stringtown field (Table 1b) show similar trends with the following exceptions. The Gordon in Jacksonburg-Stringtown is slightly coarser (medium-grained), is slightly more quartzose (74% all types of quartz grains), is less feldspathic (2.5% feldspars), and is slightly less porous (6% mean combined primary and secondary porosity).

Thin sections from both the Wileyville and Jacksonburg-Stringtown fields were assigned to individual lithofacies based on their core depth, lithology, and permeability. The results of grain size and grain mineralogy point-count analyses have been summarized for both fields (Wileyville – Table 1a; Jacksonburg-Stringtown – Table 1b). The *Fss* Lithofacies is of the most interest to this project because it comprises the actual reservoir rock within the Gordon interval. In general, the *Fss* Lithofacies is characterized by fine-grained quartz sandstone, whose grains are generally well-sorted and subangular. Grain size and grain mineralogy are similar for this lithofacies in both fields. Combined primary and secondary porosity values for the *Fss* Lithofacies range from 16.5% to 17%. Secondary porosity is primarily intragranular.

The *Fss* Lithofacies has been problematical in past studies (Matchen and others, 2001; McDowell and others, 2001) because of an inability to explain the featureless nature of the material. The lack of identifiable sedimentary structures, either physical or biogenic, can be attributed to extremely rapid deposition of fine-grained material of uniform grain size leaving a *massive* deposit; to complete homogenization of a fine-grained deposit by bioturbation removing all prior sedimentary structures; or to a combination of these effects. All of this would be academic except for the fact that materials of the *Fss* Lithofacies are also poorly cemented and highly permeable, making them good reservoir rock. Speculation on the cause for the lack of sedimentary structures (even in thin section) and the exclusion of cementation – maintenance of high permeability, has leaned towards bioturbation (McDowell and others, 2001). A thin section from the *Fss* Lithofacies in the L. S. Hoyt 100 well appears to have finally settled the argument. Figure 25b shows elongated quartz grains that have been rotated 90º to bedding, an indication of disruption of sedimentary fabric by bioturbation (Howard, 1975; 1978).

Figure 26 compares the cementation history of the Gordon sandstone in the Wileyville and Jacksonburg-Stringtown oil fields. Based on thin section examination, it appears that secondary quartz and siderite appear later as cements in the Gordon in Wileyville than in Jacksonburg-Stringtown. McDowell and others (2001) suggested that in Gordon sandstones, the presence of bioturbation, especially in the form of vertical and oblique ichnofossils, and early calcite cementation localized in bioturbated sediment formed barriers to interstratal migration of fluids. Seals between adjacent sedimentary layers probably reduced or prevented late-stage cementation and helped preserve initial permeability. Where bioturbation was more intense, the interstratal seal was more effective in preserving permeability (Figure 27).

Whole core and core plug permeability analyses were available for L. E. Dulaney 10; core plug permeability analyses were available for L. S. Hoyt 100. Analyses were performed by Core Laboratories of Dallas, TX. Results were compared to minipermeameter sampling values taken by WVGES personnel. Figure 28 presents these results in graphical fashion. As observed in previous reservoir studies (Ameri and others, 2001; Matchen and others, 2001); minipermeameter permeability values generally exceed whole core values but are less than core plug values of k_{hmax}. The advantage of using the minipermeameter is that the user can set the sample spacing and frequency and that no chemical or thermal manipulation of the core takes place prior to the measurement of permeability. The disadvantages of the minipermeameter is that only horizontal and vertical permeability measurements are possible on slabbed core and the k_h value will generally not be k_{hmax}.

ELECTROFACIES

Methodology

The two cored wells in the Wileyville field were chosen as *reference* wells for the purpose of determining electrofacies. The criteria required for reference wells have been established in reservoir characterization studies cited previously. These include: wells must be cored and have all of the following data: gamma ray, density, permeability, and grain size logs, all at a 0.25' sampling spacing. LAS (Log ASCII Standard) files were created for each reference well by first adjusting core depths to match log depths and then merging permeability (minipermeameter) and grain size data into existing digitized geophysical logs for the wells. Data within the LAS files were further restricted to the depth interval specified by the Project's stratigraphers - the Gordon interval. Next, depths for all wells were corrected to sea level by subtracting drilling depth from kelly bushing or drilling platform elevation. L. E. Dulaney 10 (103-1171) was chosen as the *superwell* (the top of the Gordon interval in this well serves as datum) for correlation purposes. Finally, all well depths were converted to metric units (subsea) so that they were compatible with the metric UTM coordinates used for geographical well locations.

A single data file was created containing: depths, gamma ray, density, permeability, and grain size (millimeters) values from reference wells. The entire range of gamma ray responses for the Wileyville field was scaled into the range [0,1] so that these values were of a similar order of magnitude as the density values. Two additional data elements (county code and permit number) were added to the file for bookkeeping purposes. Data were analyzed using the *k-Means Clustering* technique in the SPSS™ statistical software package. This technique requires the user to specify the number (k) of groups or *clusters* expected to be present within the data and to choose which data variable or combination of variables is to be used to establish the clusters. The technique proceeds to calculate *central* (mean) values for each cluster and to iteratively modify the Euclidean distance between cluster centers until centers are equidistant. If this process cannot be completed in 10 iterations for every cluster, the process is considered to have failed to produce a stable or convergent solution. Additionally, the cluster membership for every data point is saved.

The clustering process was repeated specifying 2, 3, 4, 5, and 6 clusters using a variety of variables and combinations of variables. Once all data points had been assigned to a cluster, electrofacies logs were constructed for the reference wells and displayed in the form of an electrofacies cross section. The Project's stratigrapher examined each of these cross sections and by comparison to correlations done independently using only gamma ray and density logs, decided that four electrofacies most closely resembled his work. In addition, he concluded that four electrofacies based on a linear combination of density and scaled gamma ray best matched his correlations.

The cluster membership, density, and scaled gamma ray values for every point in the reference data set were subjected to SPSS's *Discriminant Analysis* technique. This technique was used to confirm the statistical significance of the clustering solution and to generate a set of Fisher's linear coefficients that could be used to classify other geo-physical log values from the Wileyville field into the same four electrofacies. Each cluster (electrofacies) was described by a different set of Fisher's coefficients ($\hat{a}_0$, $\hat{a}_1$, $\hat{a}_2$,

... $\hat{a}_n$); where n = number of variables used to create the clusters). Cluster or electrofacies group membership is then determined for any set of data values by computing a test statistic (T) using the Fisher's coefficients for each one of the electrofacies. The data values are *plugged* into a linear equation of the form:

$$T = \hat{a}_0 + \hat{a}_1(\text{variable}_1\ \text{value}) + \hat{a}_2(\text{variable}_2\ \text{value}) + \ldots\ldots\ldots\ \hat{a}_n(\text{variable}_n\ \text{value})$$

The given data values are assigned to the cluster or electrofacies whose computed test statistic is the largest.

Once it was determined that the four cluster – density and scaled gamma ray model was a statistically and stratigraphically significant solution, the scaled gamma ray and density values from the Gordon interval for all 16 geophysical logs in the Wileyville field were extracted, and their depths converted to subsea elevations in meters. Scaled gamma ray and density values for each well were run through a computer program that determined the maximum test statistic based on Fisher's coefficients for four electrofacies. An electrofacies membership (integer values 1, 2, 3, or 4) was assigned to each pair of data values. Next, a three-dimensional electrofacies dataset was created by taking the depth, gamma ray, density, and electrofacies value for every data point in the Gordon interval from every logged well in the field and adding the UTM coordinates appropriate to each well. This information was placed into a single file that could be *sliced* to produce electrofacies maps and cross sections. Finally, permeability and grain size data were added and summary statistical analyses were performed for each electrofacies help to characterize them. Table 2 shows the resulting petrophysical characteristics of each electrofacies.

Results and Discussion

Examination of Table 2 suggests that the four electrofacies identified in the Gordon reservoir in the Wileyville field are petrophysically similar to those in the Jacksonburg-Stringtown field. The notable exception is regarding mean permeability. Electrofacies 2, 3, and 4 in Wileyville have significantly higher mean permeability than comparable units in Jacksonburg-Stringtown. However, because of the small number of reference wells available in Wileyville (2) versus Jacksonburg-Stringtown (7), it is not possible to assess the *statistical* significance of these differences.

Electrofacies identified in the Gordon from Wileyville are probably similar enough to those from Jacksonburg-Stringtown to add additional comparisons to lithofacies. The Shale Lithofacies (*Sh*) is believed to correspond to Electrofacies 1. Electrofacies 2 and 3 correspond to combinations of material from the Conglomeratic Sandstone, Laminated Sandstone, and Heterolithic Bioturbated lithofacies (*Css*, *Lss*, and *Hb*, respectively); the pay sandstone in the Gordon, a combination of Featureless Sandstone (*Fss*) and minor Conglomeratic Sandstone (*Css*) lithofacies, corresponds to Electrofacies 4.

In reservoir characterization studies cited previously, wells with geophysical logs were numerous and fairly well-distributed throughout the entire oil field. In Wileyville, this was not the case; logged wells are concentrated along the long axis of the field. Consequently, many cross sections produced by slicing the electrofacies data for these wells are not illustrative of the distribution of electrofacies for the entire field. Figure 29 shows a vertical cross section along the long axis of the field and looking to the northwest. Electrofacies 4, corresponding to the pay sandstone within the Gordon, is generally restricted to the middle of the Gordon interval. The Gordon in the Wileyville field is observed (Figure 29) to deepen to the northeast along the plunge of structure (see Figure 3). No serious lateral impediments to flow are visible in the cross section. However, a gap in well control is present in the southern portion of the field and this gap corresponds to a distinct break in IP values in the area (see Figure 18).

UPHOLE POTENTIAL – SHALLOW GAS PLAYS

Methodology

Seven shallow gas plays described in the Atlas of Major Appalachian Gas Plays (Roen and Walker, 1996) have been developed in reservoirs stratigraphically younger than the Gordon sandstone. Each play could have some potential to produce uphole gas in the Wileyville field. Therefore, the productive extent and potential of each play was examined in detail. Potential uphole gas plays are discussed below:

Middle Pennsylvanian Allegheny Formation/Group Sandstone Play (Hohn, 1996) **-** The Wileyville field lies near the axis of this northeast-southwest trending play. Gas production has been established to the east, north and west, relative to Wileyville field. Allegheny reservoirs have been developed in fluvial-deltaic sandstones associated with siltstones, shales, limestones, and coals that are known to occur over the Wileyville field. These reservoirs include the upper and lower Freeport, Kittanning and Clarion sandstones; coals in the formation include the various Freeports, Kittannings and the Clarion at the base.

Lower & Middle Pennsylvanian Pottsville, New River and Lee Sandstones Play (Hohn, 1996) **-** Wileyville lies near the axis of the play trend. Reservoirs in the play are fluvial-deltaic and nearshore sandstones. Structure enhances, but does not seem to control, production, although gas fields have been developed on the Washington anticline west of Wileyville field, and on the Littleton and Hundred anticlines to the east. The main reservoirs in these Wetzel County gas fields are the Salt sands.

Upper Mississippian Mauch Chunk and Equivalent Strata (Barlow, 1996) – The Wileyville field occurs beneath the extreme western edge of this play. Given that the Mauch Chunk sandstones are not well-developed this far west, this play has no potential above Wileyville field.

Upper Mississippian Greenbrier/Newman Limestones (Smosna, 1996) - Wileyville is just west of the axis of the play trend, but near the northern limit of play. Although scattered gas production has been established in this part of Wetzel County, most of the production from this play is in a well-established trend to the south. This play appears to have very low potential above the Wileyville oil field, although some porosity may exist in the basal part of the formation.

Lower Mississippian Big Injun Sandstone (Vargo and Matchen, 1996) – The Wileyville field lies in the center of the northern lobe of this bilobate play area. Good gas production has been established to the east, south, and west, and some to the north in Majorsville field. One could expect to encounter 175-200' of Big Injun sandstone in wells in Wileyville field. A Big Lime porosity zone overlies an unconformity in this area, with an additional porous zone in the Big Injun sandstone beneath the unconformity. However, the thickness of the Big Injun decreases to the south as the unconformity cuts deeper into the sandstone. Thus, much of the Big Injun porosity zone has been eliminated in the field area.

Lower Mississippian Weir Sandstone (Matchen and Vargo, 1996) - Wileyville lies near the northern edge of this play, and only a few gas wells have been completed to the northwest and south in Wetzel county. Furthermore, one could only expect only 50-60 feet of sandstone above Wileyville field, versus 100-125 feet in productive areas to the south. Therefore, we concluded that this play has very low to no potential in this area.

Lower Mississippian-Upper Devonian Berea and Equivalent Sandstones (Tomastik, 1996) - Wileyville lies within the play area, but there is no production from the play in Wetzel County. The true Berea trend occurs to the west in Ohio, and the Wileyville field is near the eastern edge of the shallow marine sandstone trend that produces to the west. The only sandstone above Wileyville field is probably the eastern type of Berea Sandstone that is less productive. Thus, this play has very low potential above Wileyville.

Results and Discussion

It appears that there is little or no uphole potential in the Mauch Chunk, Big Lime, Weir and Berea plays, but there may be some in the Big Injun. The best uphole potential appears to be in the shallowest plays, the Allegheny and Pottsville sandstones and their associated coals, discussed below. We have concluded that the best strategy is to develop the coal-bed methane potential of the Allegheny Formation and lower Monongahela Group.

UPHOLE POTENTIAL – COAL-BED METHANE

Methodology

There is a long history of gas production from coal beds in the Appalachian basin. During two WVGES studies (Patchen and others, 1991; Bruner and others, 1995) conducted for the Gas Research Institute (now Gas Technology Institute) in the 1990's, a map was prepared showing the locations of all wells from which gas shows from coal beds had been reported and all wells producing gas from coal beds. These coal-bed methane wells were all drilled on or near the axes of subsurface anticlines, where the coals are structurally high and water-free (Figure 30).

Additionally, maps of initial potential and cumulative production and a decline curve were produced, along with maps of net coal thickness, thickness of the single thickest coal, and the number of coals reported per well greater than 2 feet in thickness

A stratigraphic framework for Pennsylvanian coals and sandstones for this area was established by Patchen and others (1991) and further enhanced by Bruner and others (1995) from cores taken for coal tests and from logs of adjacent gas wells (Figure 31). The Sewickley, Redstone, and Pittsburgh coal beds occur in the lower 100-110 feet of the Monongahela Group, with the Pittsburgh defining the base of the group. Only two named coals, the Bakerstown and Mahoning, are present in the 550-600 foot Conemaugh Group below. Several marine zones and red beds occur in the lower half of the Conemaugh, which typically is described as barren of coal. The underlying Allegheny Formation is defined by the upper Freeport coal at the top and the Clarion coal at the base, above the Homewood sandstone at the top of the Pottsville Group. Other coals in the Allegheny include, from top to bottom, the lower Freeport, and the upper, middle, and lower Kittanning coal beds.

Major structural features in Wetzel County trend northeast-southwest, and include the Washington, Littleton and Hundred anticlines, and the Ninevah syncline (see Figure 3). Oil is produced from the Gordon sandstone in the Ninevah syncline; gas is produced from coal beds on each of the major anticlines and on several smaller, associated anticlines. In all cases, gas is produced from coals that are structurally high and water-free. No production has been established in structurally low, water-filled coals, even though the gas content in coals in these structural areas should at least equal, if not exceed, the gas content on water-free structural highs that may have been partially depleted over time.

The best coal-bed methane production in Wetzel County has been from the Pittsburgh coal in Big Run field, which was developed on a small bifurcating structure mapped on the eastern flank of the Littleton anticline. The smaller Pine Grove field was developed on a small anticline west of the larger Littleton structure. Additional wells with production from the Pittsburgh coals were drilled on the Hundred anticline, due east of Big Run field, and to the northeast on the Littleton anticline, near the Pennsylvania border. Gas shows were reported from the Pittsburgh coal in wells drilled on the Washington anticline to the northwest. However, to the southwest along this structure, where it plunges in that direction, water was reported in the Pittsburgh.

Three types of coal-occurrence maps were produced for the previously cited studies, primarily using information in the WVGES oil and gas database: isopach, isolith, and isopleth maps of the lower Monongahela and entire Allegheny intervals. Although the Pittsburgh coal usually is reported by oil and gas well drillers, other coals, especially coals below the Pittsburgh, commonly are not, even when present. Other than the Pittsburgh, the shallower Washington, Waynesburg, and Sewickley are reported more often than the deeper Allegheny coals, and thus are cased off by drillers, in accordance with the rules and regulations governing drilling in West Virginia.

Because of this, gamma ray-density log combinations were used to map coal occurrence in the Allegheny Formation. Usually 4-6 coals can be observed on the logs in wells drilled in and around Wileyville field. The cumulative thickness of these coals ranges from 10 to 20 feet over the area, with the single thickest Allegheny coal usually being 4-5 feet thick. Drillers' records which reported the younger Pittsburgh and Sewickley coals, indicate cumulative thickness generally less than 12 feet, with the thicker Pittsburgh less than 8 feet.

Gas potential for Wileyville from the Pittsburgh and Sewickley coals was calculated by digitizing areas of common thickness within the Wileyville field taken from contoured maps of coal thickness for the Sewickley, Pittsburgh, and total Allegheny coals. Gas content of 150 Scf/ton was assumed for the Sewickley and Pittsburgh coals and 200 Scf/ton for the deeper Allegheny coals; a coal density of 1800 tons/acre-foot was assumed. Results are summarized in Tables 3a and 3b.

Results and Discussion

The significance of structural control on coals in the Wileyville area seems to be that it allows operators to produce gas from coal beds that are water-free; the gas is not structurally controlled. Indeed, gas probably occurs in the coals throughout the area, even in structurally low areas like the Ninevah syncline (see Figures 3 and 30).

Previous work (Bruner and others, 1995) defined two, prospective coal-bed methane intervals: the Monongahela interval, essentially from the Sewickley to the Pittsburgh coal; and the deeper Allegheny interval. The Allegheny interval was expanded to include the younger Mahoning coal bed in the lower part of the overlying Conemaugh Group. Channel-fill sandstones of conventional oil and gas reservoir quality are associated with these coals and have produced gas for decades. Much of this gas may have actually come from associated coal beds, so the gas potential in the Allegheny coals has probably been reduced. In spite of this, the potential of the Allegheny interval is thought to exceed that of the younger Monongahela Group because Allegheny coals are of higher rank and contain greater total gas content per ton of coal (Kelafant and others, 1988; Hunt and Steele, 1991).

Average thickness of the coals in these two intervals, based on cores taken at eight locations in Wetzel County, West Virginia and Greene County, Pennsylvania, is approximately 14-15 feet for the Monongahela coals and 11-12 feet for the deeper Allegheny coals. Thus, one could expect approximately 25 feet of coal to be encountered in these two prospect intervals in much of northern West Virginia.

Coal rank is relatively uniform in northern West Virginia, with coals falling within the high-volatile B and A bituminous ranks. Data from five cores taken near Big Run field show a consistent vitrinite reflectance of the Pittsburgh coal in the R_{max} = 0.69 - 0.70% range (Bruner et al, 1995). Although thermally derived coal-bed methane initially appears when vitrinite reflectance ranges from 0.8% to 1.0%, Hunt (1979) showed that a small amount of gas can be produced at lower values, in the 0.6% to 0.7% range.

Vitrinite reflectance values for coals below the Pittsburgh generally are higher than the shallower coals, so it might be assumed that gas content values for the deeper coals also would increase. This has proven to be the case in adjacent parts of Pennsylvania, where gas content values for the Freeport, Kittanning and Clarion coals were in the 192 to 252 Scf/ton range (Markowski, 1993).

The Sewickley-Pittsburgh prospect interval contains a higher percentage of coal than the deeper Mahoning-Clarion interval, and based on coal thickness and coal volume per acre, would be a more attractive coal-bed methane target than the Allegheny prospect interval. However, these deeper coals have a lower ash content, higher rank, and higher gas content per ton, and this may compensate for the lower ton per acre values of these coals.

Estimates of coal-bed methane potential should take into account historical production from coals in the general area of the Wileyville field and specific parameters of the potential coal reservoirs. Although the main reservoir in the Big Run and Pine Grove fields is the Pittsburgh coal, gas shows were reported from the Sewickley coal in at least nine Big Run wells and three Pine Grove wells. Both fields produced for many years in spite of low initial open flows and low rock pressure. Final open flows in Big Run field ranged from 8 to 121 Mcf/d/well, with an average of 38.5 Mcf/d. All but four wells, which were shot with nitroglycerine, were natural producers. No water problems were reported, with the exception of the discovery well which produced for 36 years before water problems developed.

In Pine Grove field, open flows from the Pittsburgh ranged from 8 to 60 Mcf/d, with an average of 28 Mcf/d. Only one well was shot; the others were natural completions. More than 2 billion cubic feet of gas has been produced from Big Run field, plus an undetermined volume from Pine Grove field.

The volume of gas desorbed from the Pittsburgh coal varies according to location, rank and depth of the coal sample. Gas content values for the Pittsburgh coal range from 100 Scf/ton to as much as 200 Scf/ton, generally from west to east, across the Pittsburgh coal basin in northern West Virginia. Core samples taken from the Pittsburgh coal near Big Run field contained less than 50 Scf/ton at a depth of 520 feet, but it is reasonable to assume that the gas content of the Pittsburgh coal in this area has been depleted by more than 50 years of production in the Big Run field (2.1 Bcf cumulative). A more reasonable estimate for gas content in the Pittsburgh in this area is 140-150 Scf/ton of coal.

Examination of Tables 3a and 3b suggests that the total gas contained in the Sewickley coal within the confines of the Wileyville field is 3.09 Bcf. For the Pittsburgh coal, this figure rises to 7.21 Bcf and for the combined Allegheny coals, the estimated gas content is 25.44 Bcf. Thus, the total gas in place for both coal-bed methane intervals, two coals in the lower Monongahela and six coals in the Allegheny, is approximately 35.74 Bcf for the area encompassed by the Wileyville oil field.

The Wileyville field is in close proximity to two established areas of coal-bed methane production: the Pine Grove and Big Run gas fields. Production in both fields is structurally enhanced, if not controlled, and a gas-water contact is present in both fields. In contrast, the Wileyville oil field lies near the axis of the Ninevah syncline to the west. All of the coal beds present above the Gordon oil reservoir are expected to be water-filled in this area. Thus, before any gas could be produced from these coal beds, dewatering of the coals in the syncline would be necessary. However, it is suggested that in de-watering the coals to establish coal-bed methane production, an important source of water for the continuation of the Wileyville waterflood in the Gordon oil reservoir could be developed.

Our recommendation is to conduct an engineering study to determine the feasibility of producing water through shallow wells drilled through the Clarion coal and completed in multiple coals, and injecting this water into the Gordon oil reservoir through deeper injection wells. Under this scenario, the produced water would have an immediate value, whereas in a typical coal-bed methane de-watering scenario, one has to wait until water production declines and gas production begins to begin to receive a return on investment.

CONCLUSIONS AND RECOMMENDATIONS

Field History

From 1900 to 1905, the entire producing reservoir in Wileyville was delineated by the drilling process. Based on our previous experiences with reservoir characterization of siliciclastic reservoirs in West Virginia, we believe that this pattern of completions is indicative of a relatively low degree of reservoir heterogeneity.

Lithofacies, Stratigraphic Framework, and Production

Five lithofacies can be recognized: Featureless sandstone (*Fss*), Laminated sandstone (*Lss*), Conglomeratic sandstone (*Css*), Shale (*Sh*) and Heterolithic bioturbated (*Hb*). Each lithofacies is relatively distinctive in core and has a recognizable pattern on geophysical logs.

Fss sandstones have a density of around 2.3 g/cm^3 which makes the lithofacies very easy to distinguish as the primary reservoir for the field. Permeability shows a similar relationship – the highest permeabilities are for *Fss* sandstones, with a mean value greater than 90 mD.

The distribution of lithofacies *Fss* within the Gordon is inconsistent. In the southern part of the Wileyville field, *Fss* sandstones are continuous and probably well-connected. However, in the northern part of the project, *Fss* sandstones thin to almost zero thickness, suggesting that the northern part of the study area is not well-suited to waterflooding.

The spatial pattern of initial potentials in the northern half of the field is irregular, consistent with the presence of several reservoir compartments in this part of the field. Overall, there is a suggestion of poor communication between the two halves of the field, consistent with the stratigraphic model.

Petrography and Petrophysics

Cements in the Gordon, in order of appearance, include calcite, clays, quartz overgrowths, and siderite. Combined primary and secondary porosity values in the Gordon range from 3% to 17% with a mean value of 9%. Secondary porosity is primarily intragranular and is often associated with the alteration or dissolution of feldspars.

The *Fss* Lithofacies is characterized by fine-grained quartz sandstone, whose grains are generally well-sorted and subangular.

The *Fss* Lithofacies has been problematical in past because of an inability to explain the featureless nature of the material. *Fss* sandstones are also poorly cemented and highly permeable, making them good reservoir rock. A thin section from the *Fss* Lithofacies shows elongated quartz grains that have been rotated 90º to bedding, an indication of disruption of sedimentary fabric by bioturbation.

Early calcite cementation localized in bioturbated sediment formed barriers to interstratal migration of fluids. Seals between adjacent sedimentary layers probably reduced or prevented late-stage cementation and helped preserve initial permeability. Where bioturbation was more intense, the interstratal seal was more effective in preserving permeability.

Minipermeameter permeability values generally exceed whole core values but are less than core plug values for k_{hmax}.

Electrofacies

Four electrofacies were identified in the Gordon reservoir in the Wileyville. The pay sandstone in the Gordon, a combination of Featureless Sandstone (*Fss*) and minor Conglomeratic Sandstone (*Css*) lithofacies, corresponds to Electrofacies 4.

A vertical electrofacies cross-section along the long axis of the field suggests Electrofacies 4, corresponding to the pay sandstone within the Gordon, is generally restricted to the middle of the Gordon interval. The Gordon in the Wileyville field is observed to deepen to the northeast along the plunge of structure. No serious lateral impediments to flow are visible in the cross section. However, a gap in well control is present in the southern portion of the field and this gap corresponds to a distinct break in IP values in the area.

Uphole Potential

The best uphole potential appears to be in the shallowest plays, the Allegheny and Pottsville sandstones and associated coals, and in developing the coal-bed methane potential of the Allegheny Formation and lower Monongahela Group. Total gas in place for two coals in the lower Monongahela and six coals in the Allegheny, is approximately 35.74 Bcf for the area encompassed by the Wileyville oil field.

Coal beds present above the Gordon oil reservoir are expected to be water-filled in this field. In de-watering the coals to establish coal-bed methane production, an important source of water for the continuation of the Wileyville waterflood in the Gordon oil reservoir could be developed.

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East Resources provided cores, geophysical logs, production data, and scientific insight into the history and challenges of the Wileyville oil field. James Britton (WVGES) performed the majority of the thin-section point-counting work. Chris Howton (WVU-Geology and Geography) aided in the selection of thin-section materials to be used as photo illustrations.

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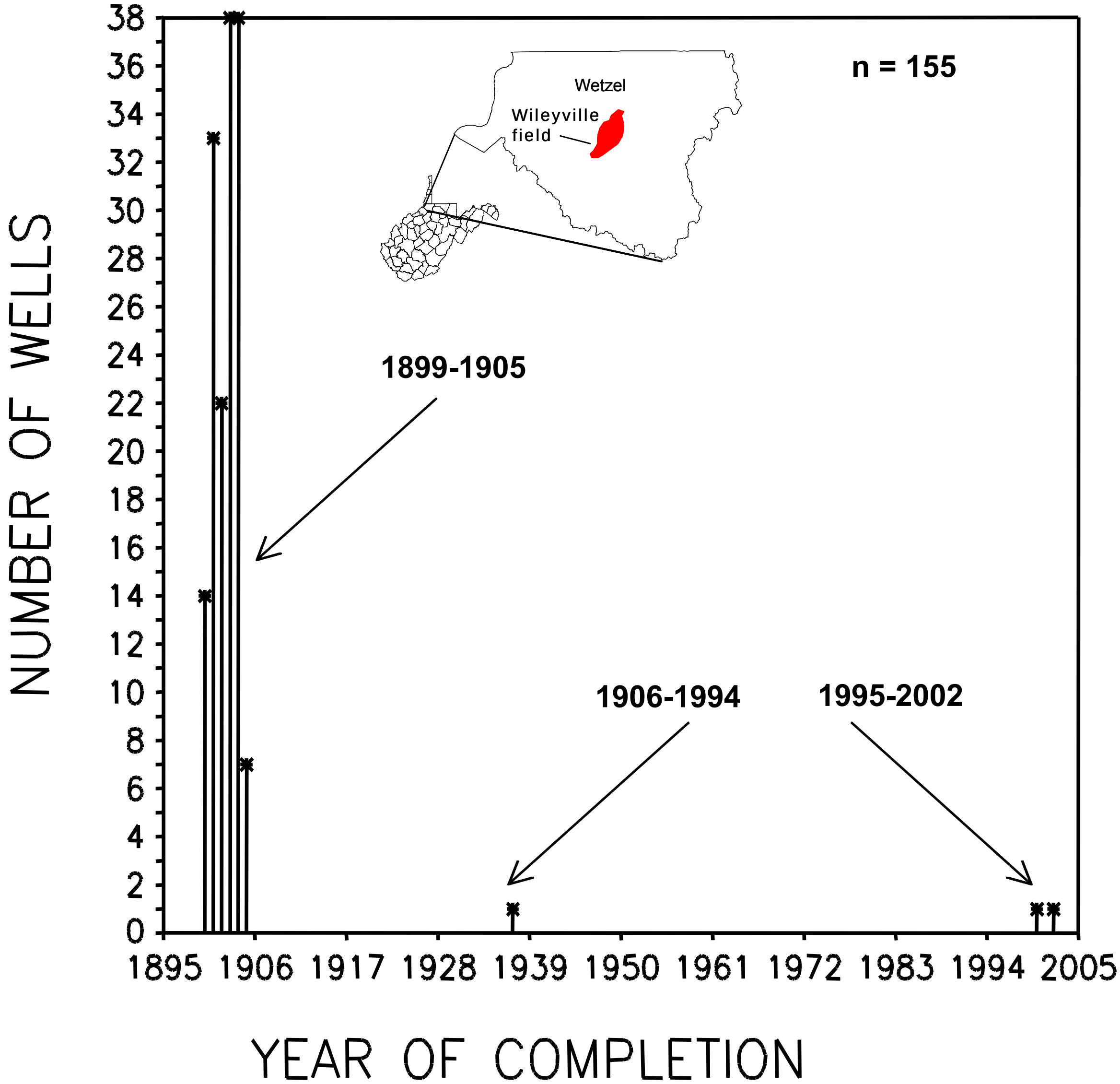
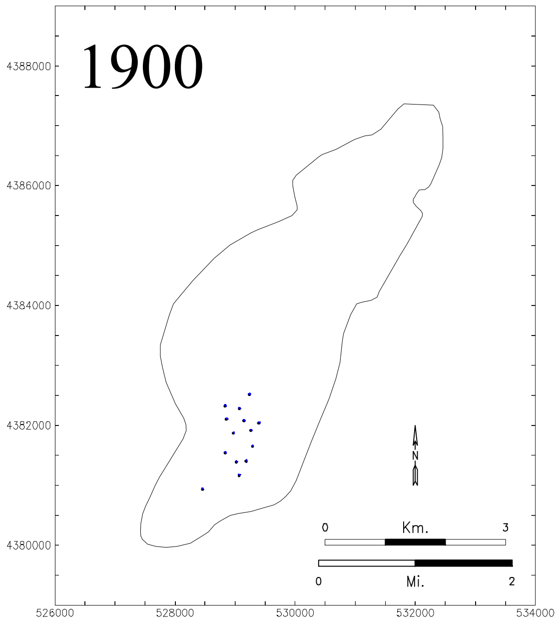
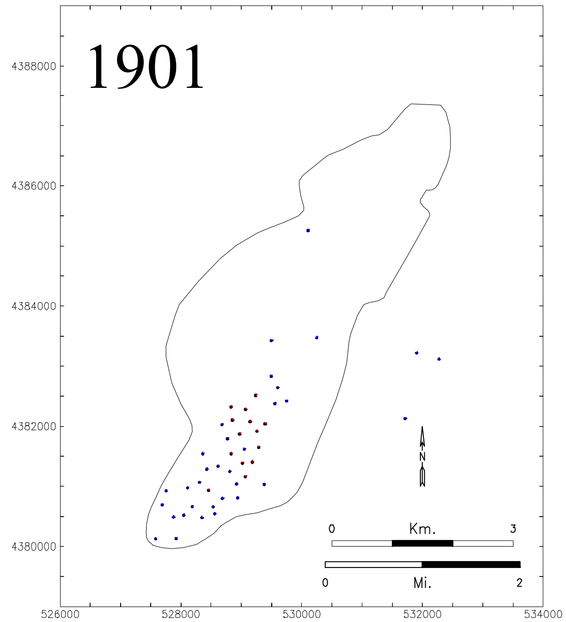


Figure 1. Plot of the time-domain spectral analysis of completions of producing oil wells in the Wileyville oil field. Three clusters are apparent; only the first (1899-1905) contains a significant number of wells. Inset map shows the location of the Wileyville field in northern West Virginia.





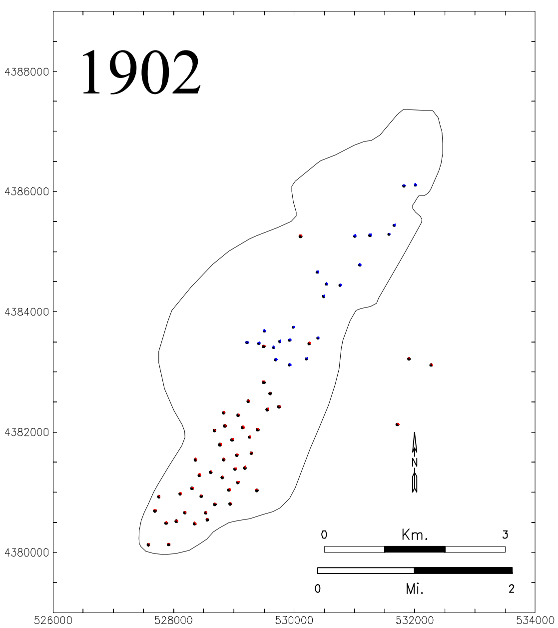
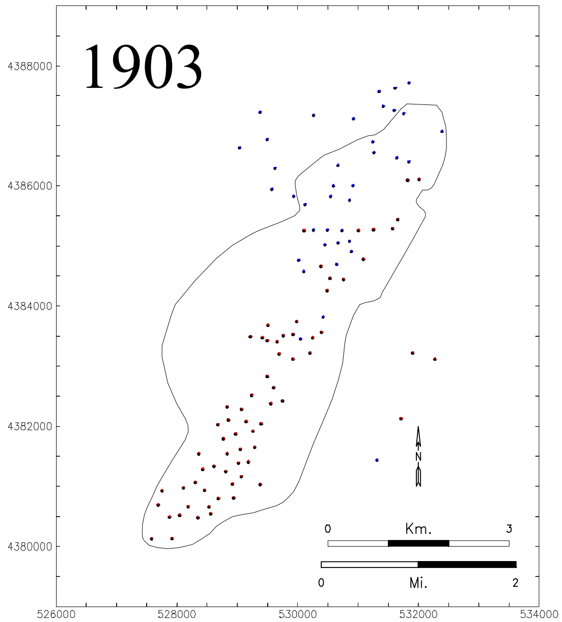
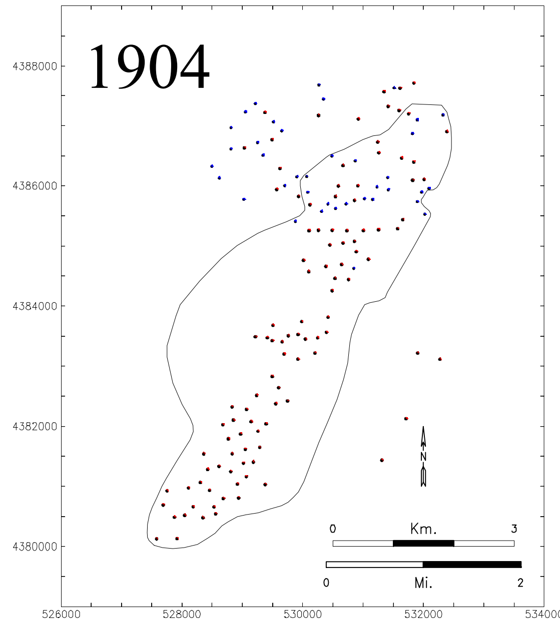


Figure 2. Locations of producing oil wells completed during initial development of the Wileyville oil field. Discovery starts in the southern portion of the field.





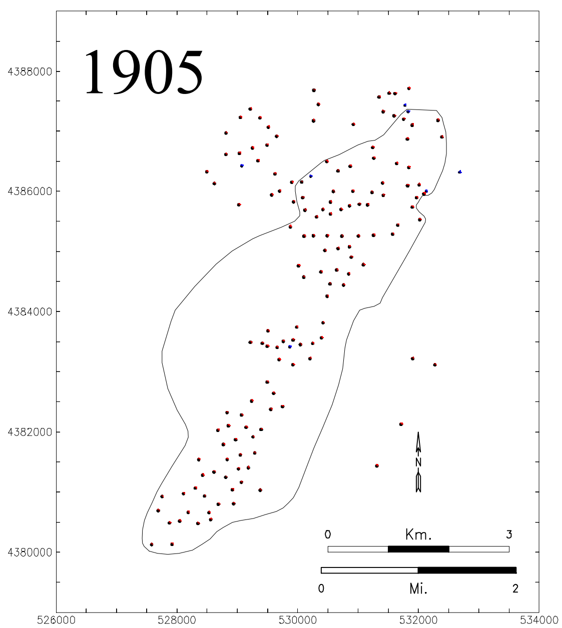


Figure 2. (continued)

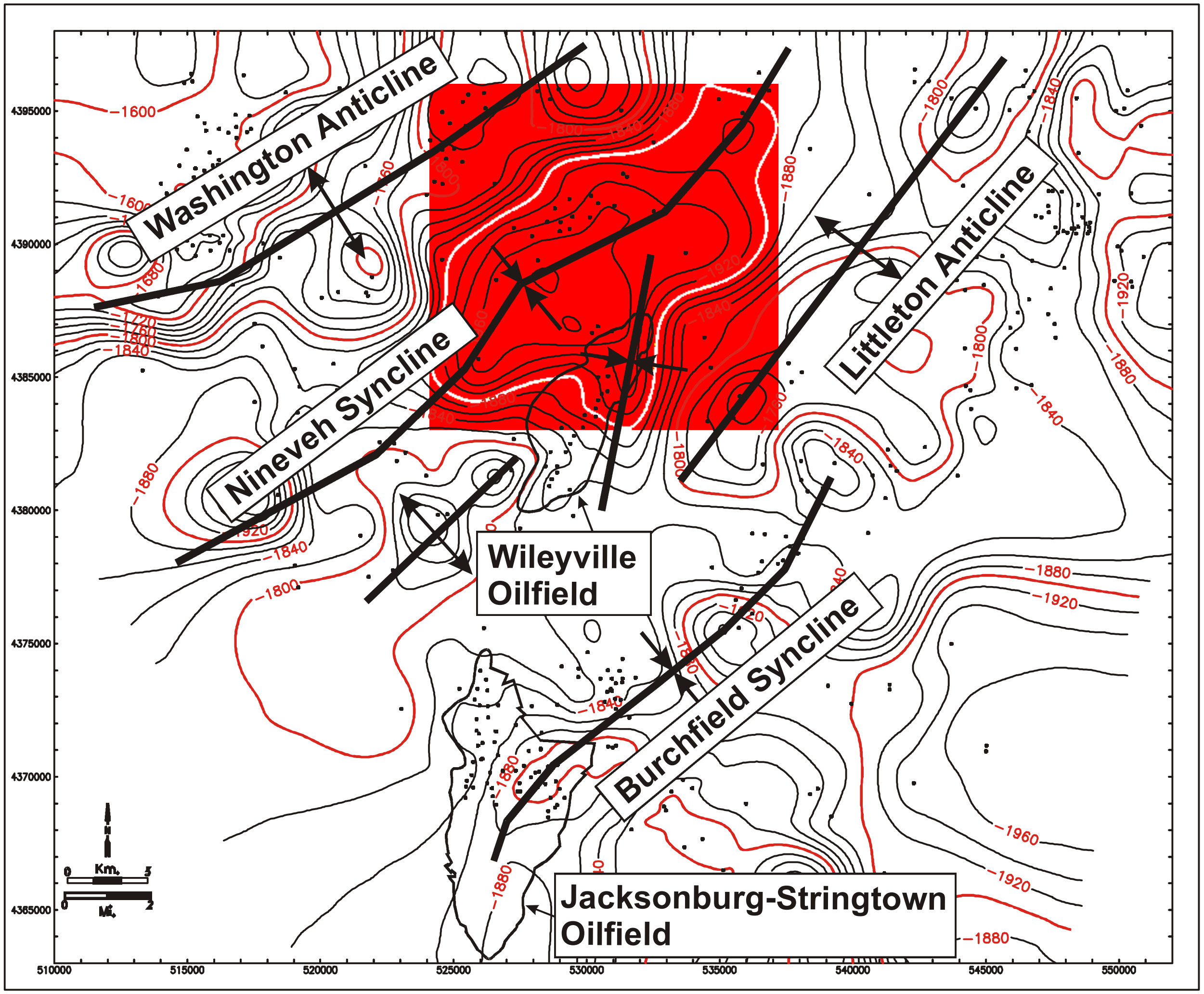


Figure 3. Structural contour map on the the top of the Gordon sandstone in the Wileyville area. Outlines of the Wileyville and Jacksonburg-Stringtown oil fields are superimposed on the map.

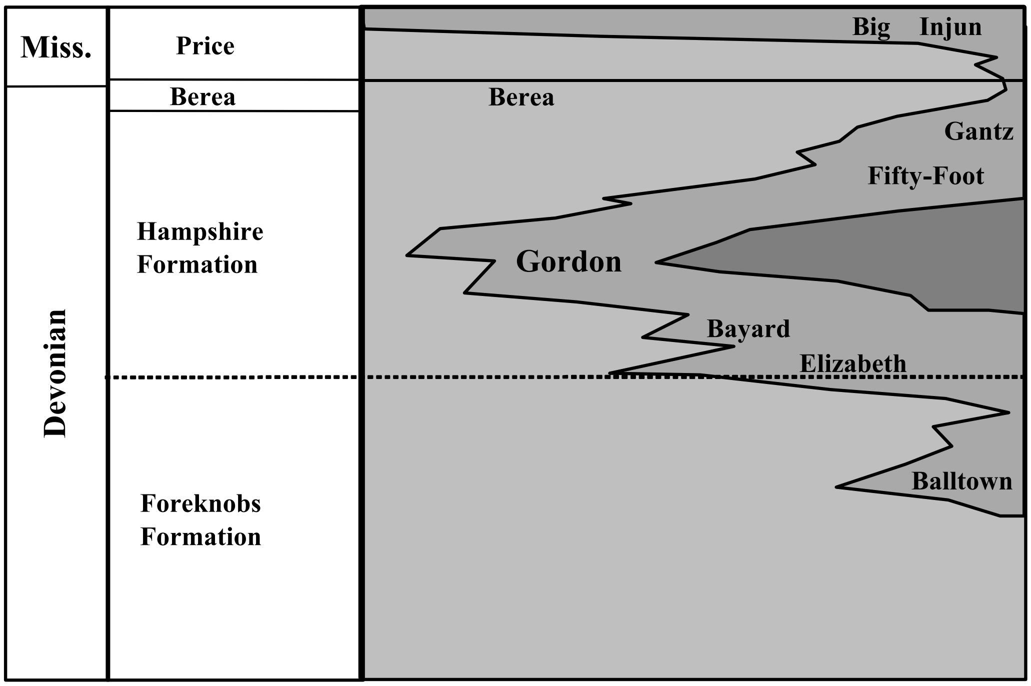


Figure 4. Generalized stratigraphic column for the study area including both outcrop and subsurface terminology.

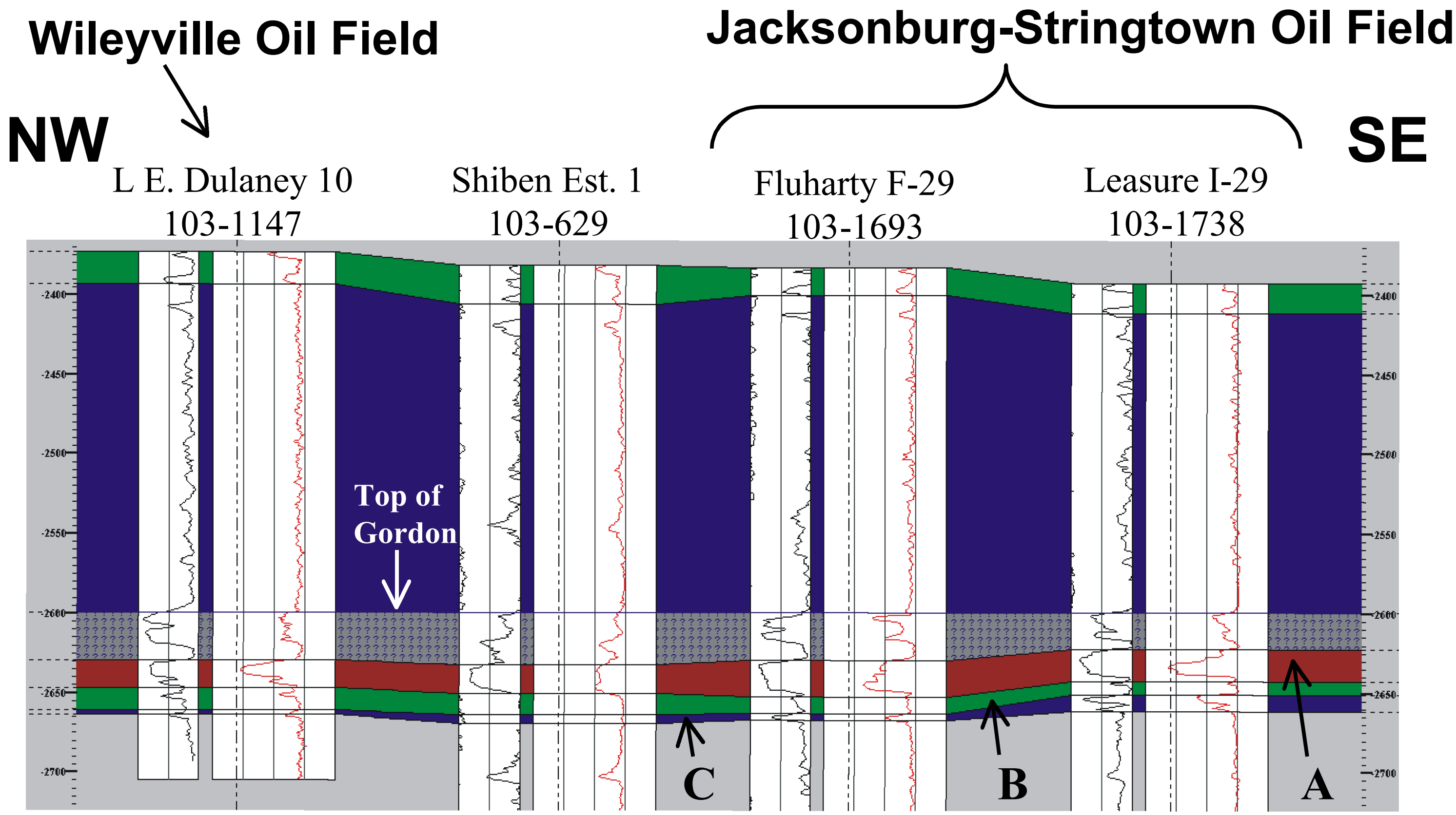


Figure 5. Correlation of Gordon wells in Wetzel County, WV. Datum is the top of the Gordon. The sandy portions of parasequences B and C pinch out to the northwestward of the Stringtown Oilfield. Only Parasequence A is recognizable in the Wileyville Oilfield. The uppermost parasequence comprised of lithofaces Hb serves as a recognizable marker. Gamma ray curves are to the left, density curves are to the right. No horizontal scale implied.

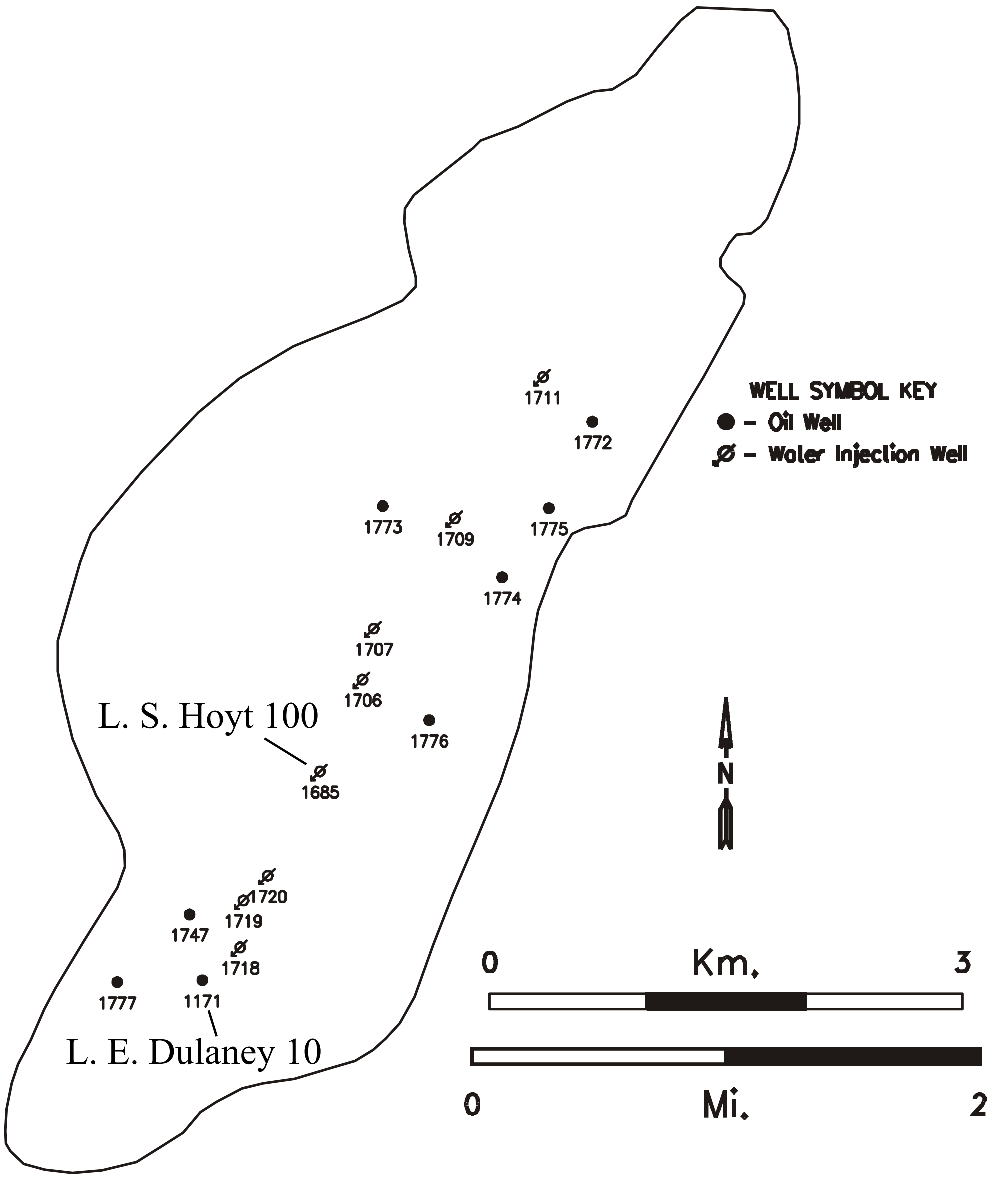


Figure 6. Location of the two cored wells in the Wileyville field (L. S. Hoyt 100 and L. E. Dulaney 10). Also shown are the locations of wells with geophysical logs used used to identify electrofacies.

Figure 7. L.S. Hoyt 100, 3154', Heterolithic bioturbated (*Hb*) Lithofacies with vertical burrow (*Diplocraterion?* sp.).

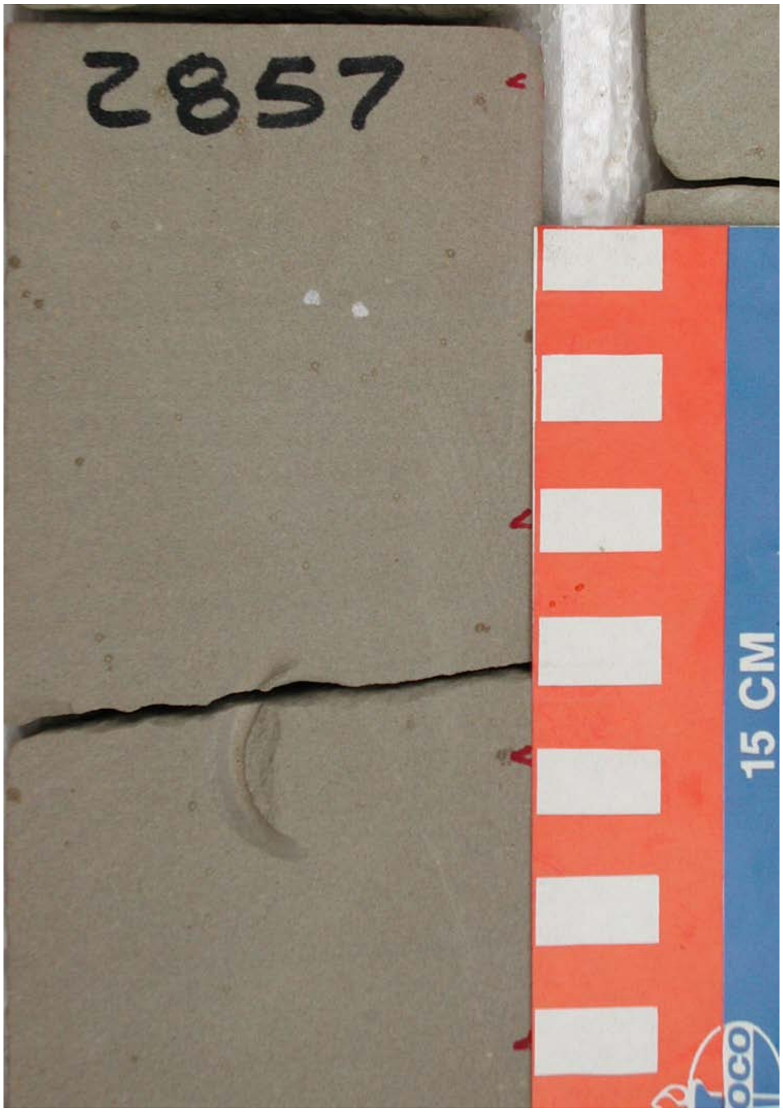


Figure 8. L.E. Dulaney 10, 2857', Featureless sandstone (*Fss*) Litho-facies. Note the absence of sedimentary structures and the presence of isolated quartz pebbles.

Figure 9. L.E. Dulaney 10, 2840', Laminated Sandstone (*Lss*) Lithofacies showing ripple-scale crossbedding.

Figure 10. L.E. Dulaney 10, 2850', Conglomeratic sandstone (*Css*) Lithofacies. Clasts are a combination of quartz pebbles and sideritic shale rip-ups.

CORE/SECTION # L.E. Dulaney #10 (103-1171)
LOCALITY Wetzel Co., WV
Core = Log + 4'

FORMATION : Gordon
DESCRIBED BY: Sheehan and McDowell

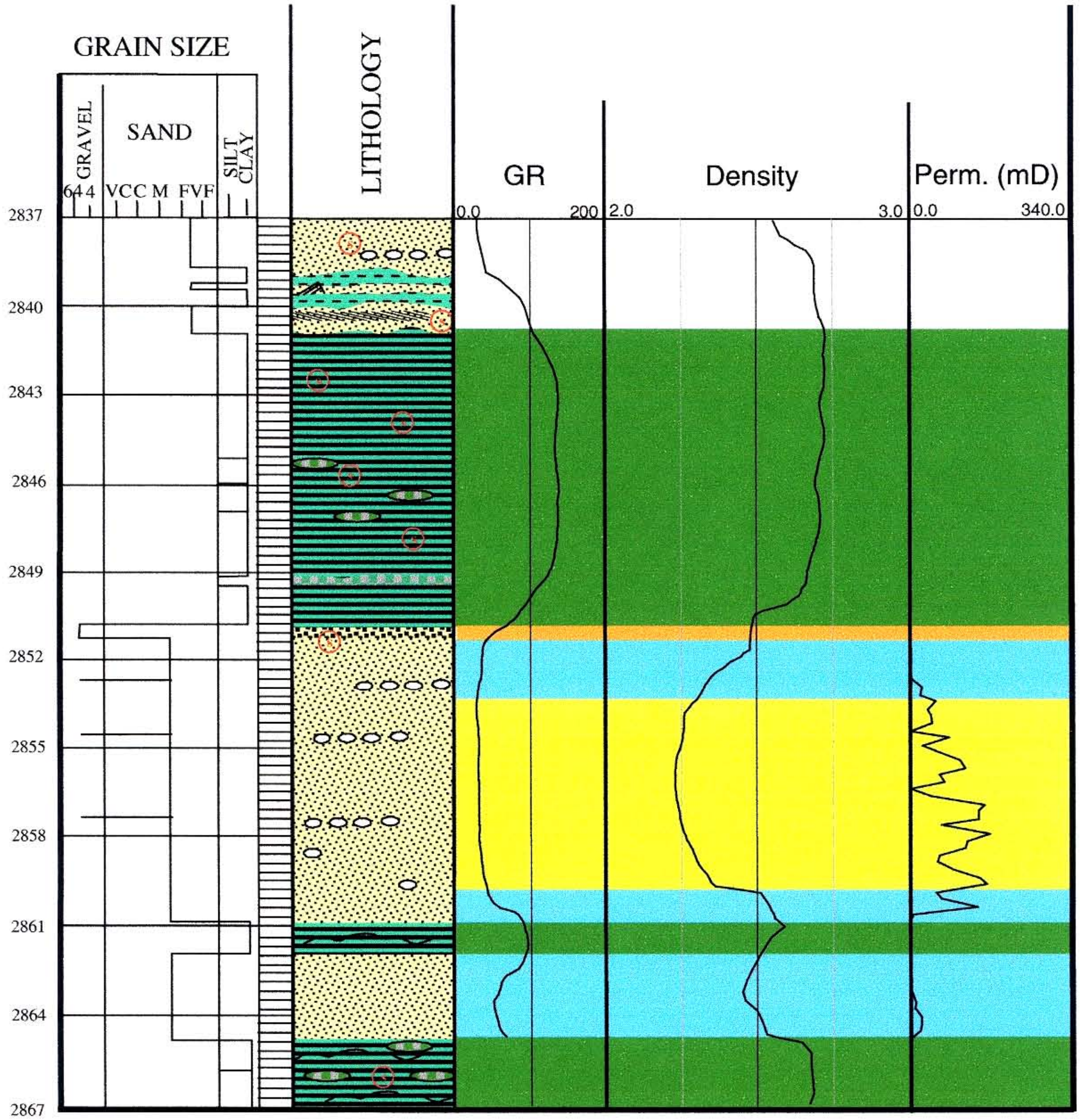


Figure 11. Correlation of L.E. Dulaney 10 core to wireline log. Note the differentiation of *Fss* (yellow) from *Lss* (blue) and *Css* (orange) in log. Lowest bulk density readings correspond to *Fss*. Permeability measured by minipermeameter is shown on the right.

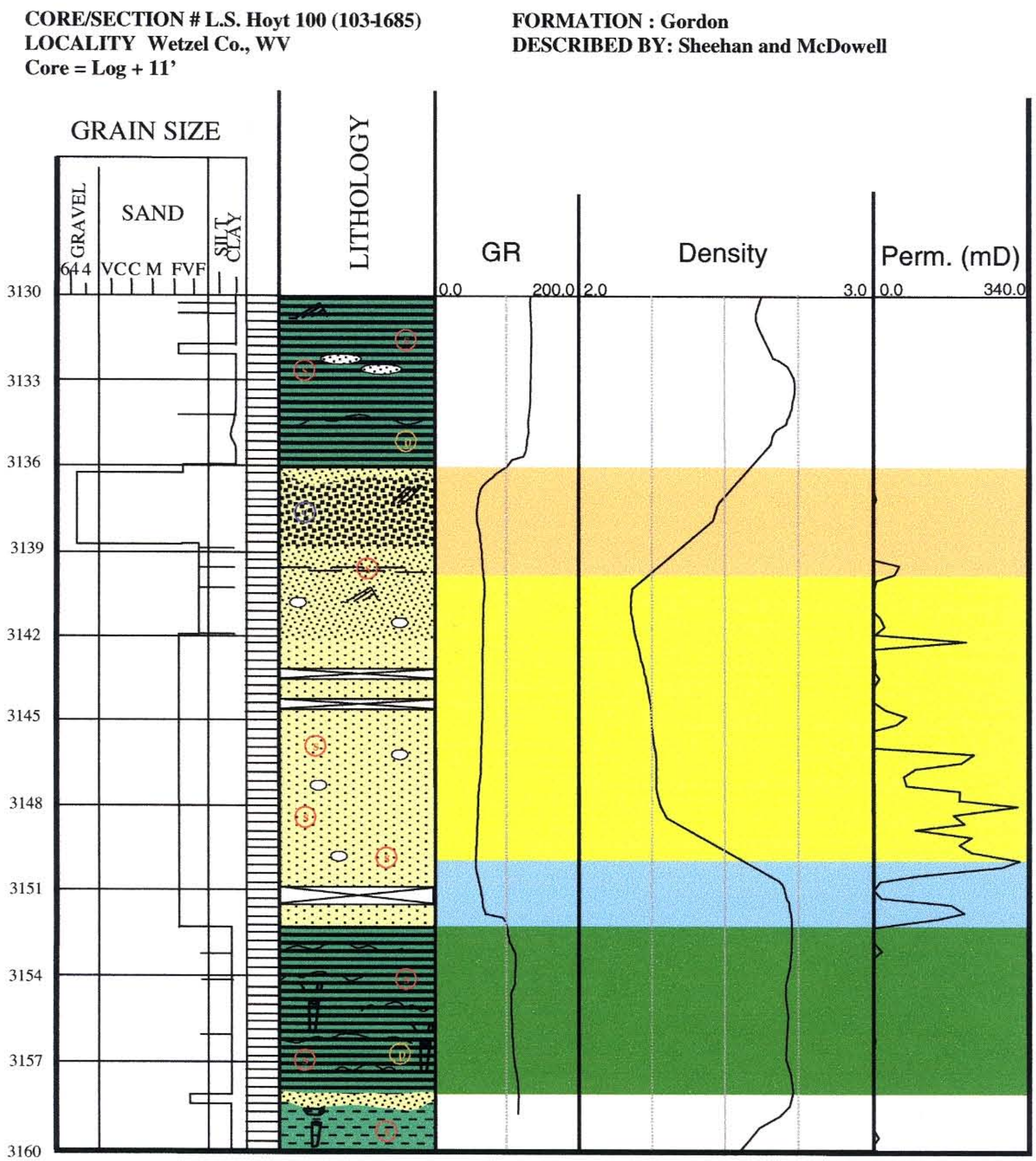


Figure 12. Correlation of L.H. Hoyt 100 core to wireline log. Note the differentiation of *Fss* (yellow) from *Lss* (blue) and *Css* (orange) in log. The lowest bulk density readings correspond to *Fss*. Permeability measured by minipermeameter is shown on the right.

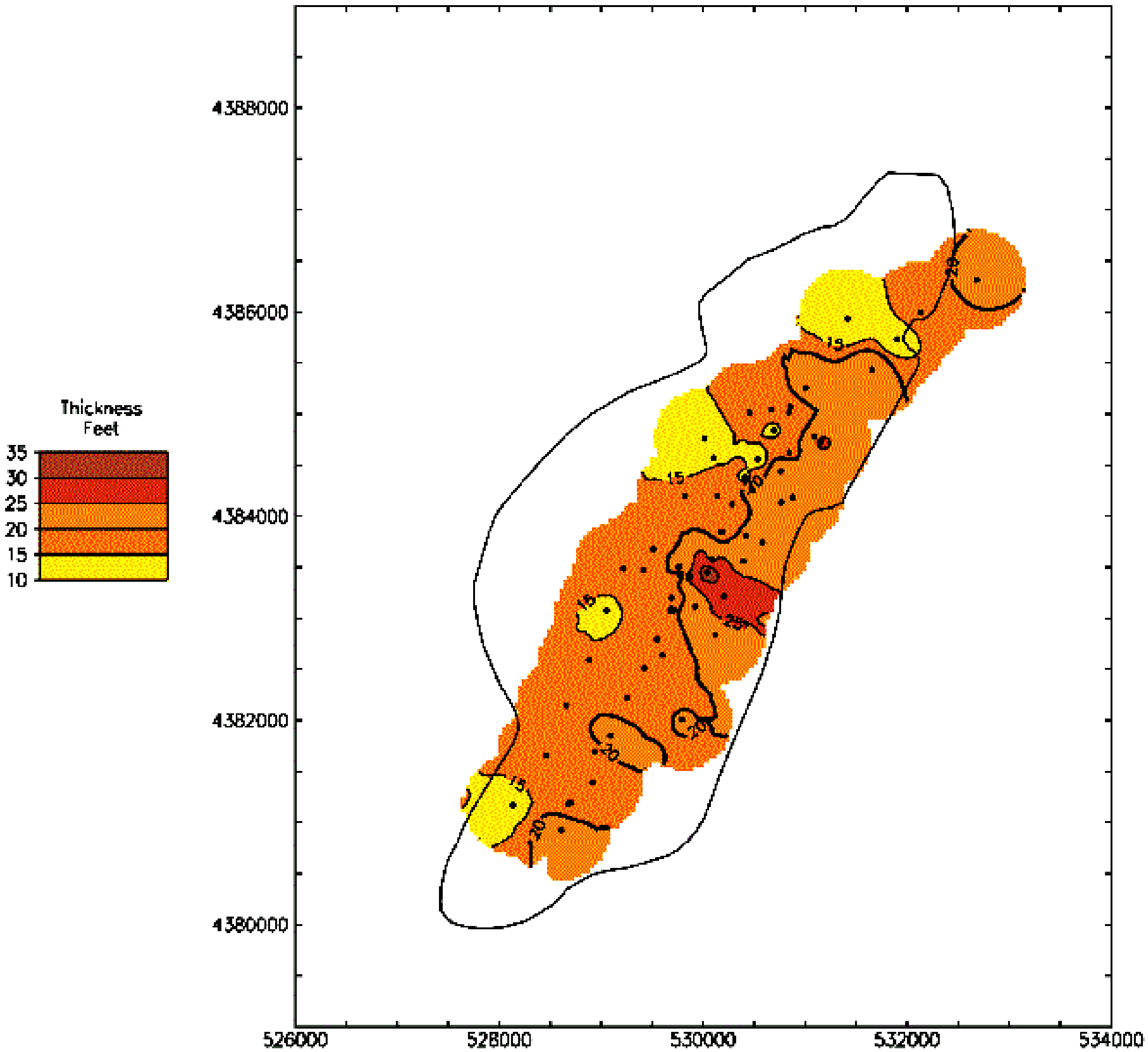


Figure 13. Map of total Gordon thickness for the Wileyville oil field. Outline of the field has been superimposed on the map

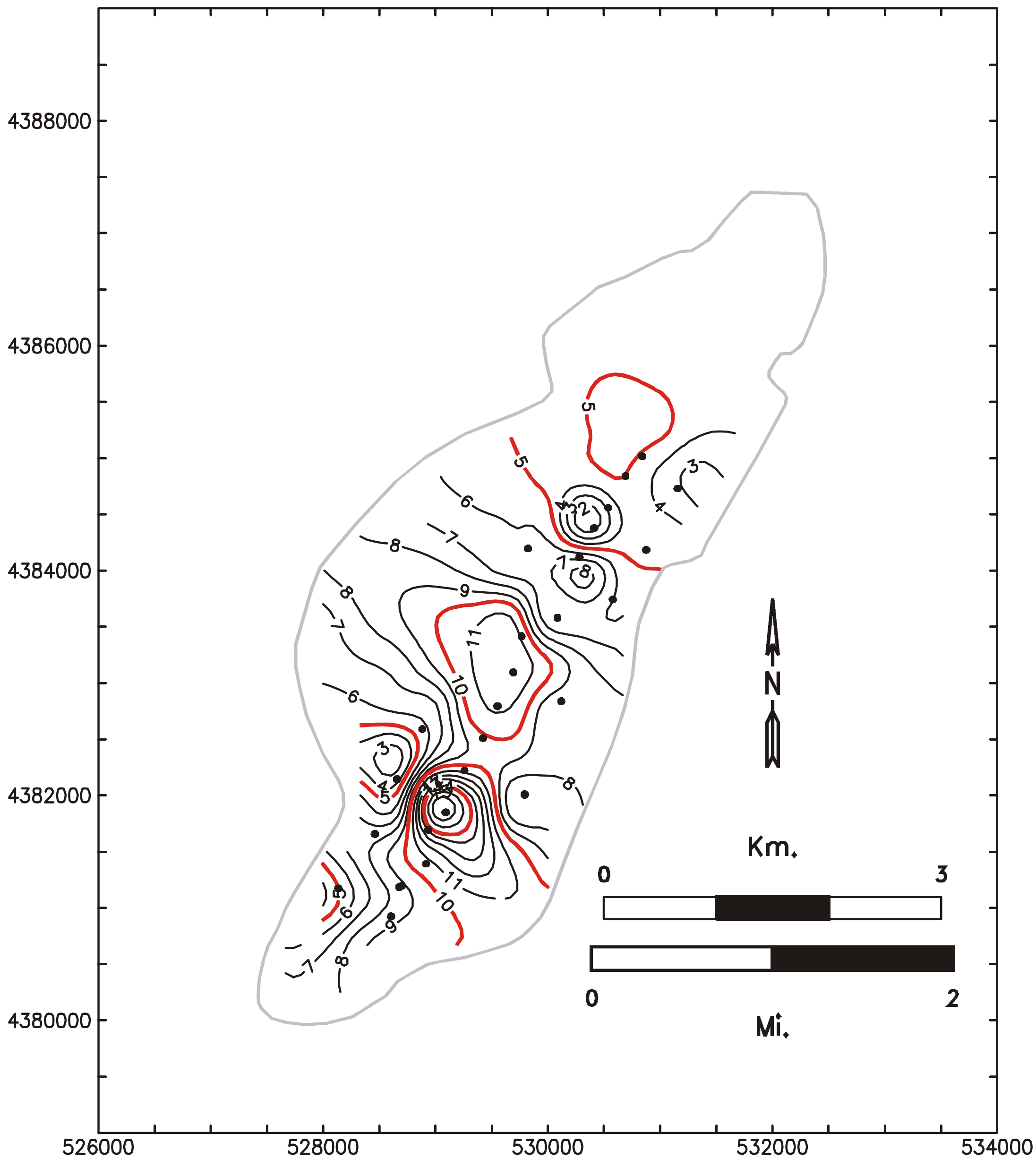


Figure 14. Map of thickness of *Fss* lithofacies within the Gordon for the Wileyville oil field. Contour interval is 1 foot.

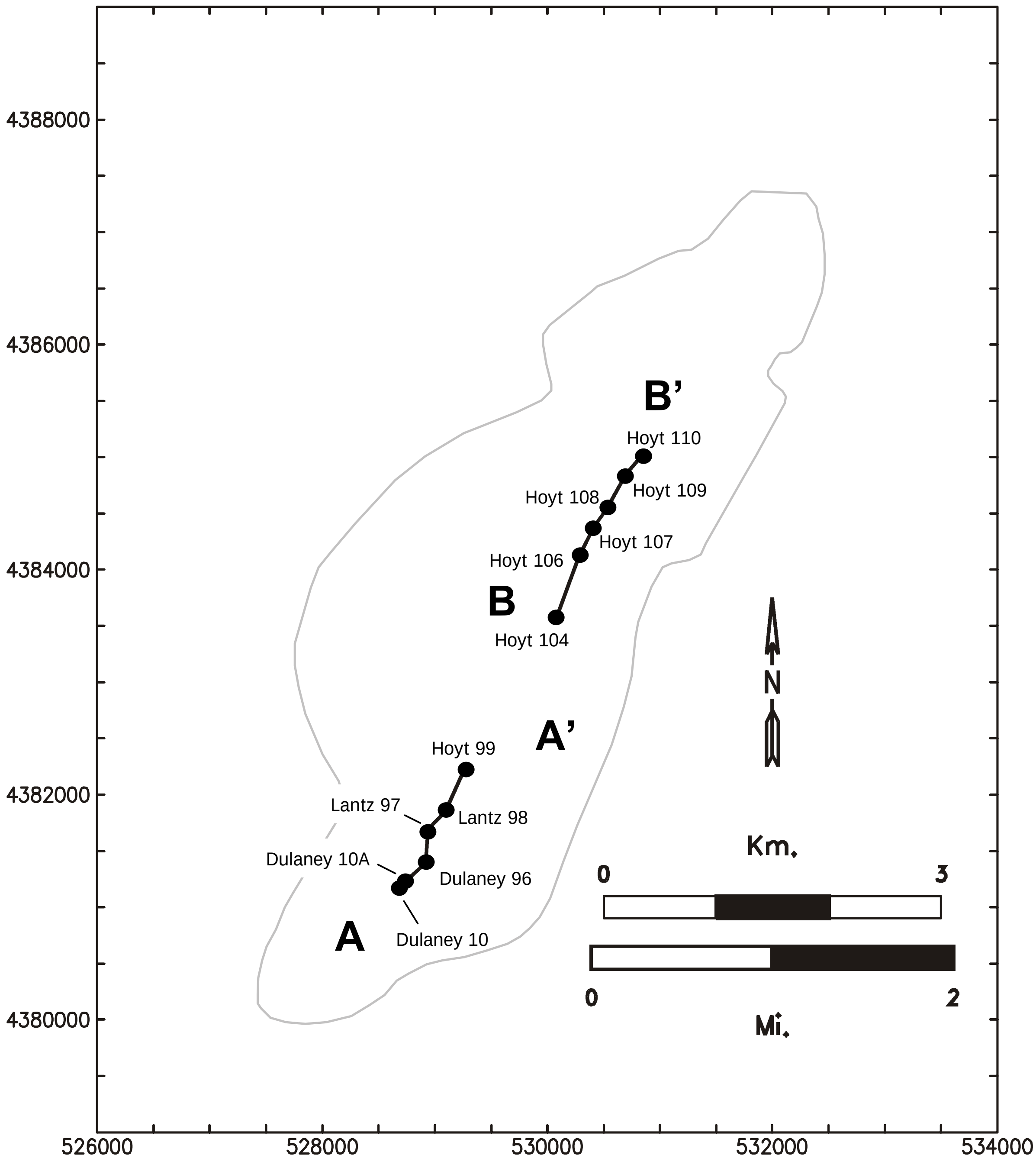


Figure 15. Location of stratigraphic cross-sections.

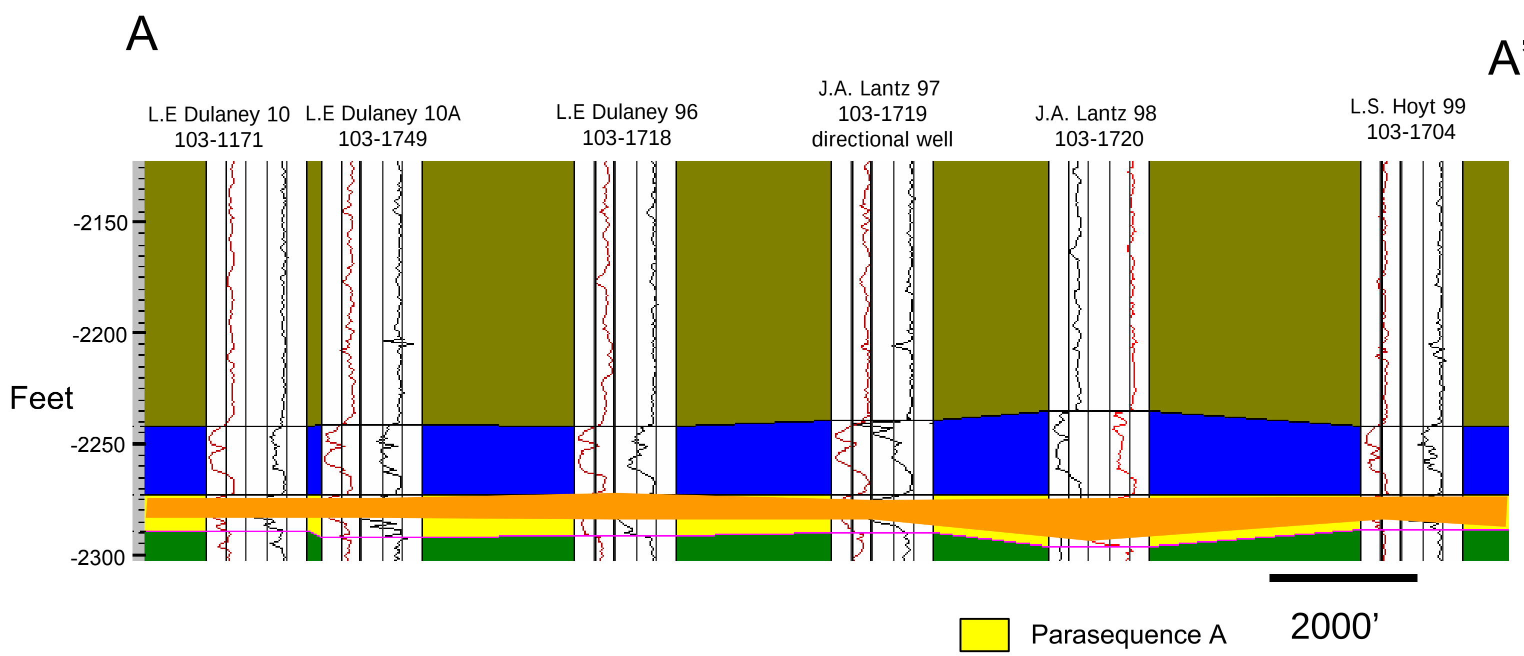


Figure 16. Stratigraphic cross section A-A'. See Figure 15 for the location of the cross section.

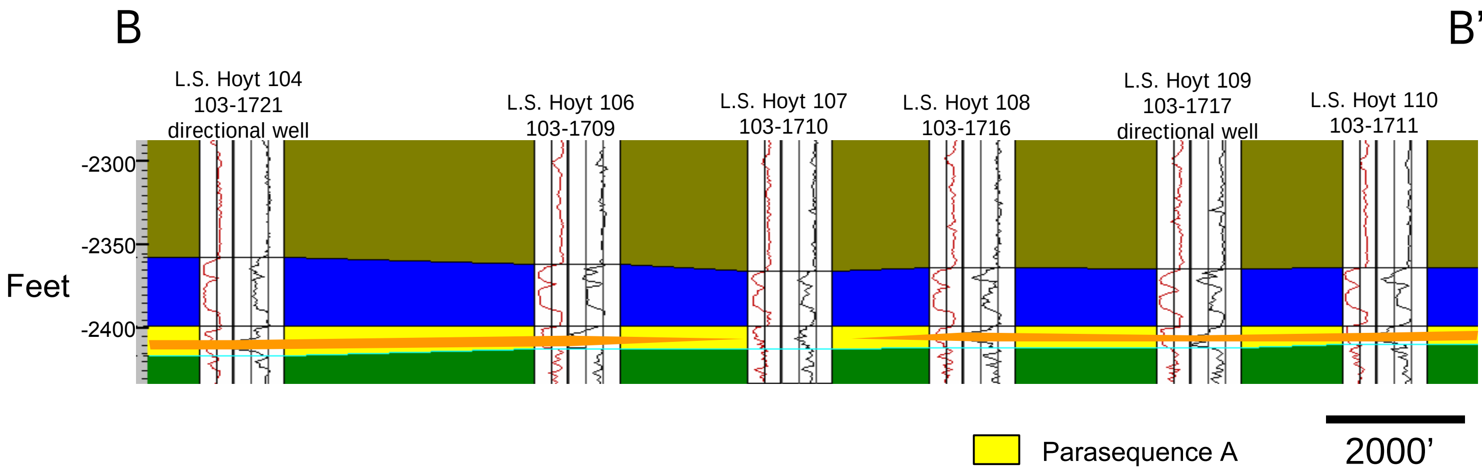


Figure 17. Stratigraphic cross section B-B'. See Figure 15 for the location of the cross section.

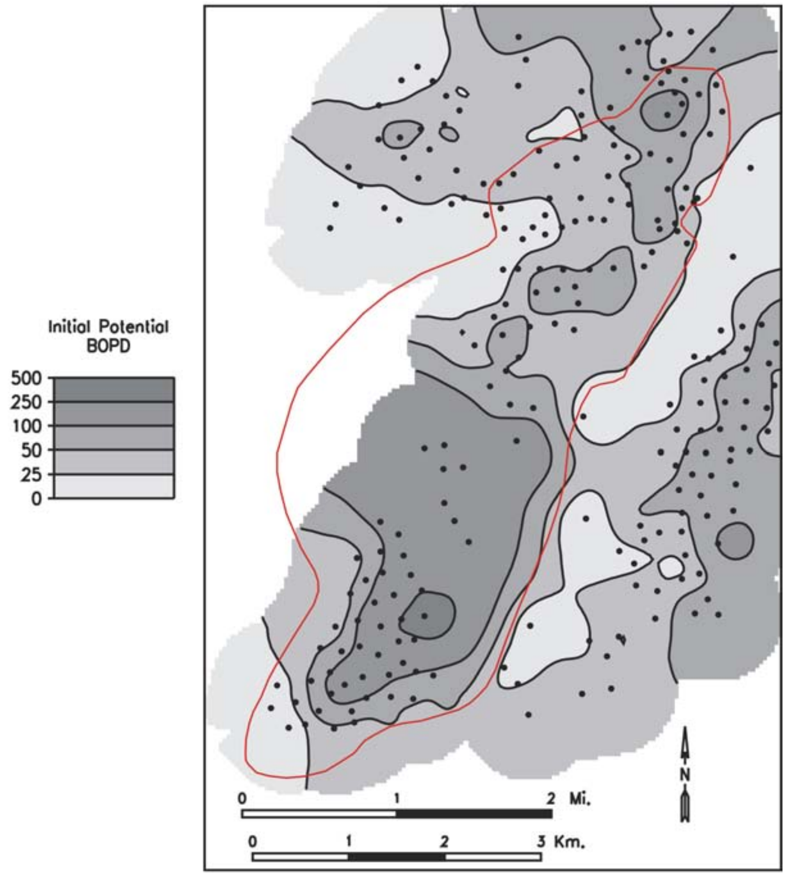


Figure 18. Contour map of oil initial potential in Wileyville oil field and vicinity. Field outline is shown in red.

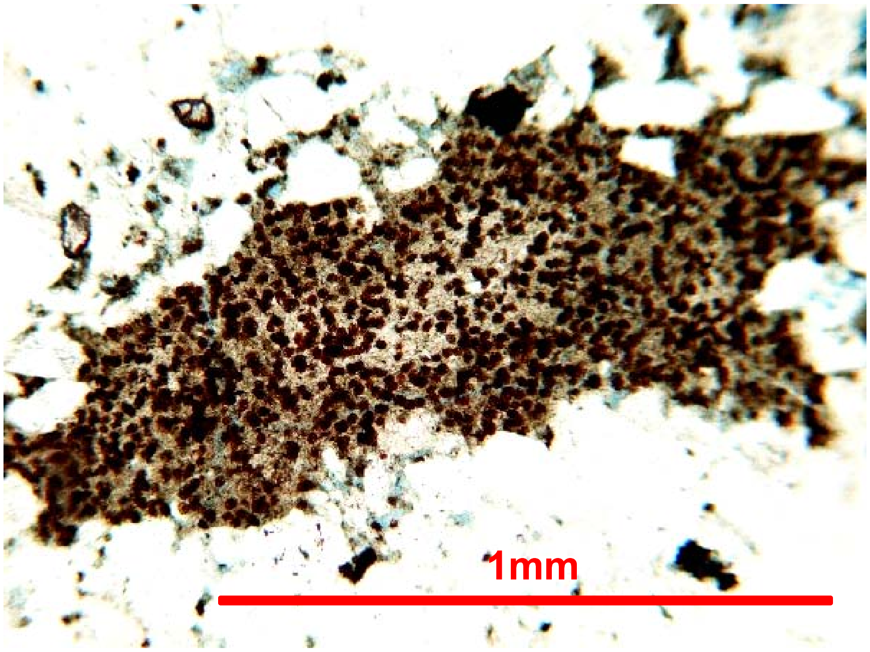


Figure 19a. Sideritic shale clast in a fine- to very fine-grained quartz sandstone from L. E. Dulaney 10 (103-1171) at a depth of 2850.25'; plain light.

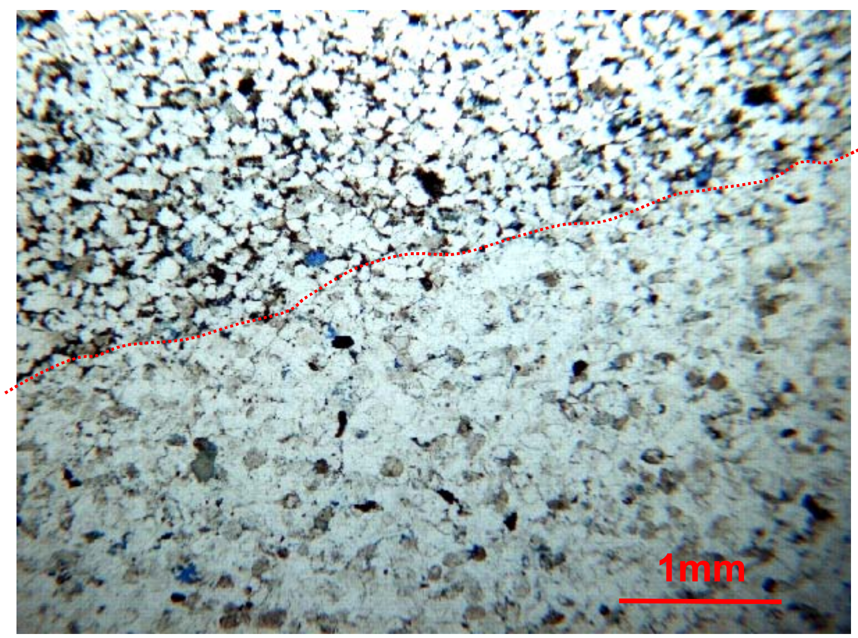


Figure 19b. Siderite front (top of slice above dashed line) in a fine- to very fine-grained quartz sandstone from L. E. Dulaney 10 (103-1171) at a depth of 2852.25'; plain light.

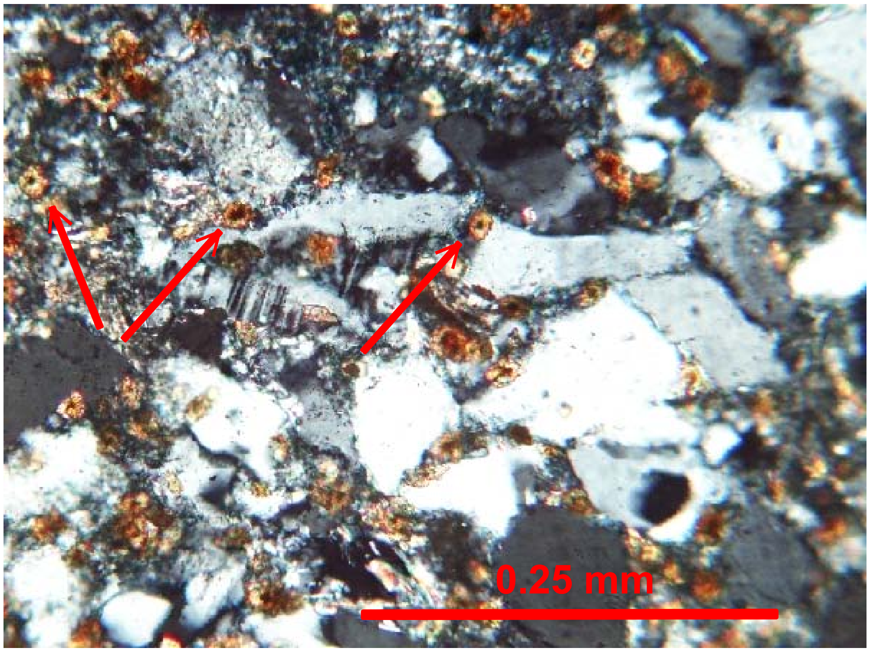


Figure 20a. At higher magnification (25x), siderite *blebs* are seen to be poorly developed rhombs with dark, ferruginous centers. From L. E. Dulaney 10 (103-1171) at a depth of 2840.50'; crossed polars.

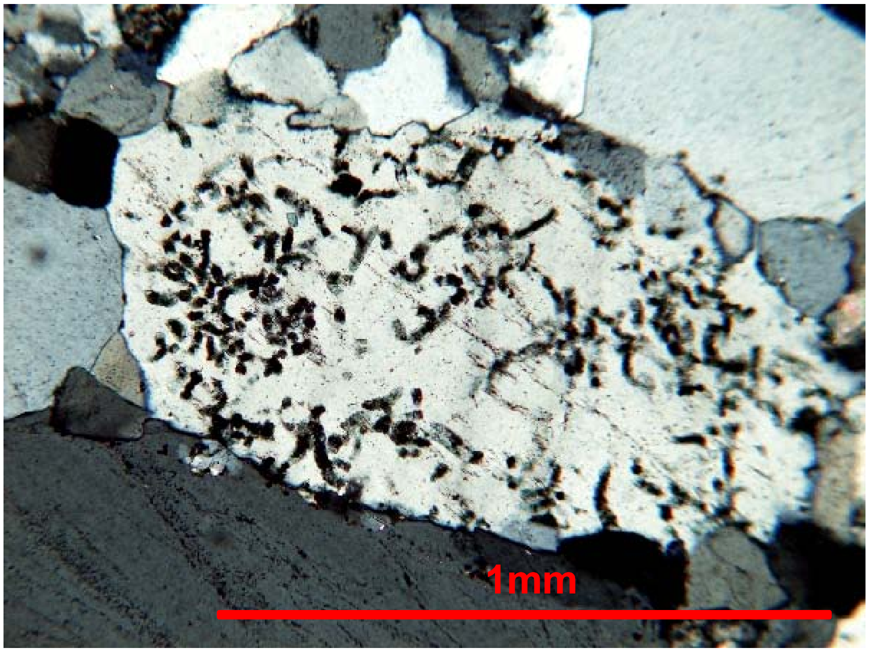


Figure 20b. Vermicular chlorite alteration in a subrounded quartz grain sandstone in a fine- to very fine-grained quartz sandstone from L. S. Hoyt 100 (103-1685) at a depth of 3137.45'; crossed polars.

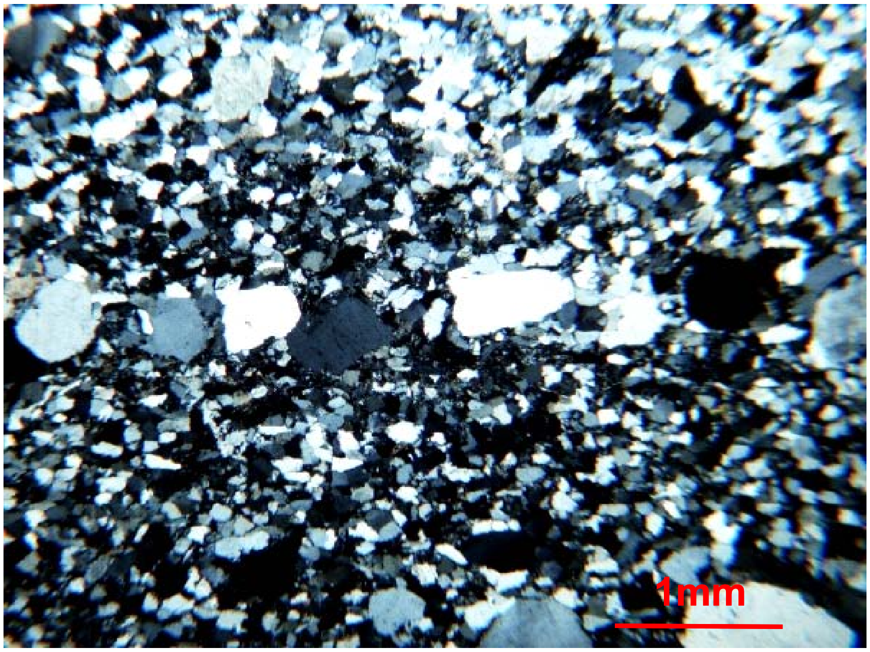


Figure 21a. Layer of moderately well-rounded quartz granules in a fine- to very fine-grained quartz sandstone from L. S. Hoyt 100 (103-1685) at a depth of 3137.45'; crossed polars.

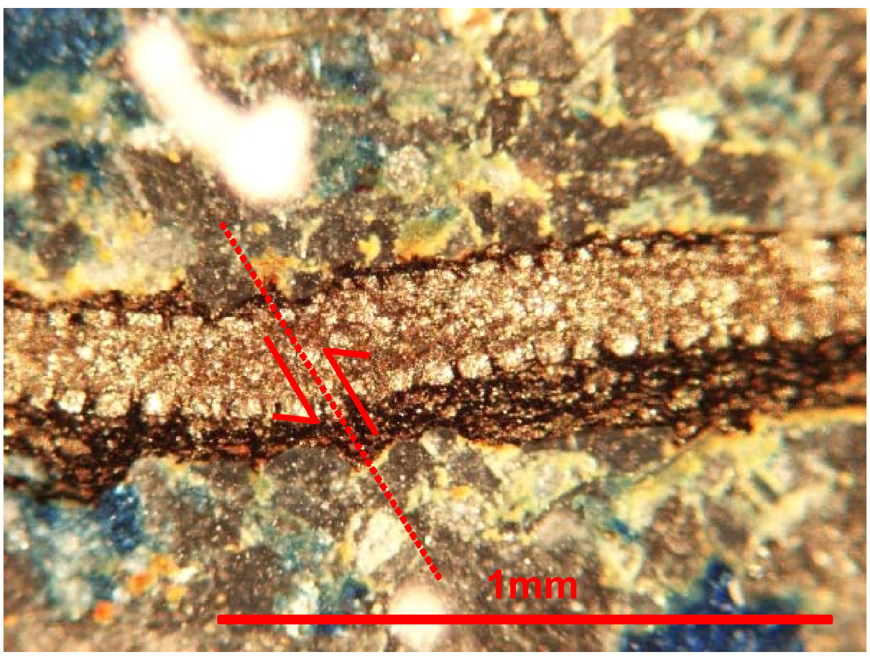


Figure 21b. Pyritized plant fragment showing displacement by a microfault. From L. S. Hoyt 100 (103-1685) at a depth of 3138.05'; reflected light.

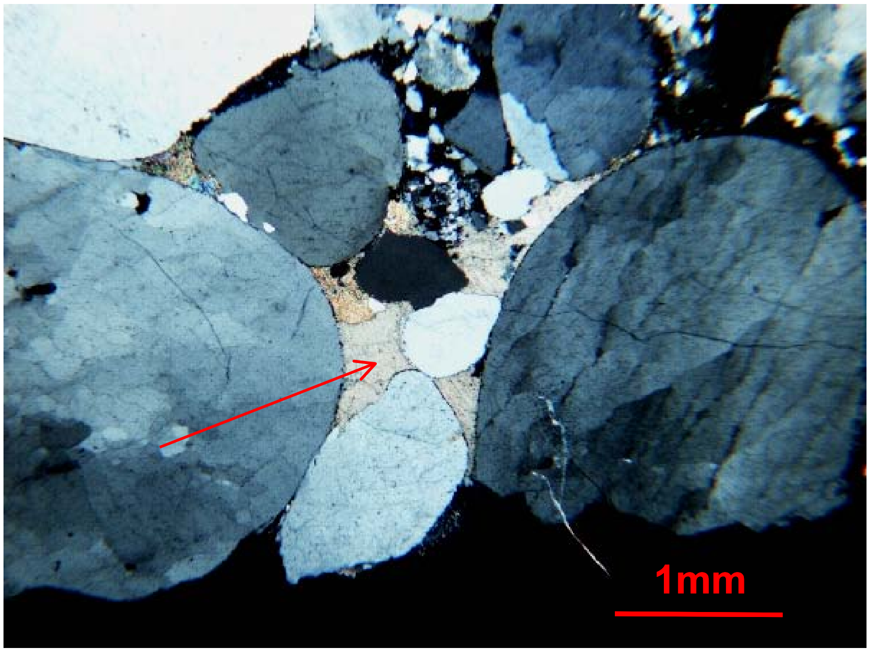


Figure 22a. First-stage, sparry calcite cement filling pore space between well-rounded quartz pebbles. From L. S. Hoyt 100 (103-1685) at a depth of 3138.05'; crossed polars.

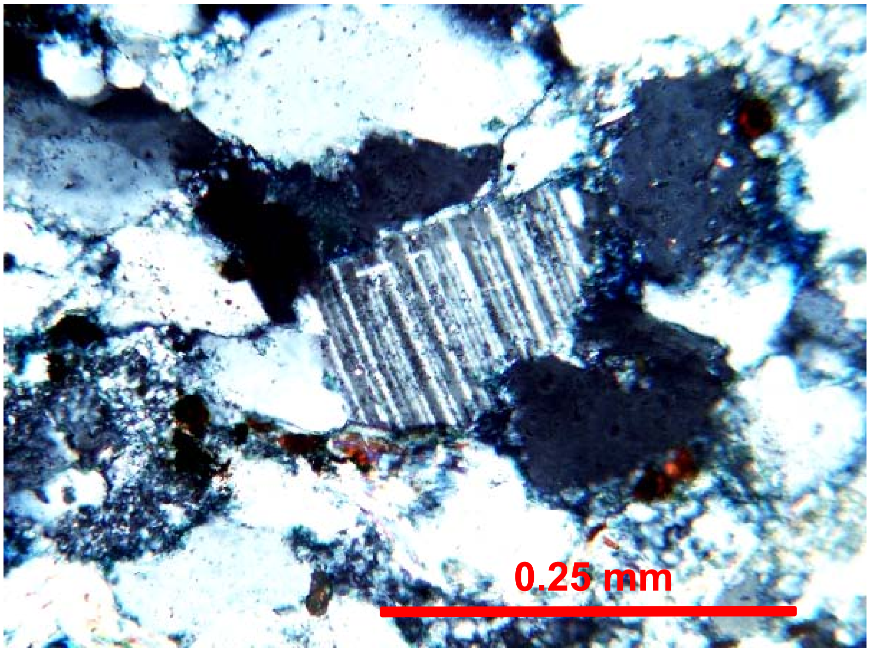


Figure 22b. Intact plagioclase grain showing no secondary porosity. From L. E. Dulaney #10 (103-1171) at a depth of 2838.65'; crossed polars.

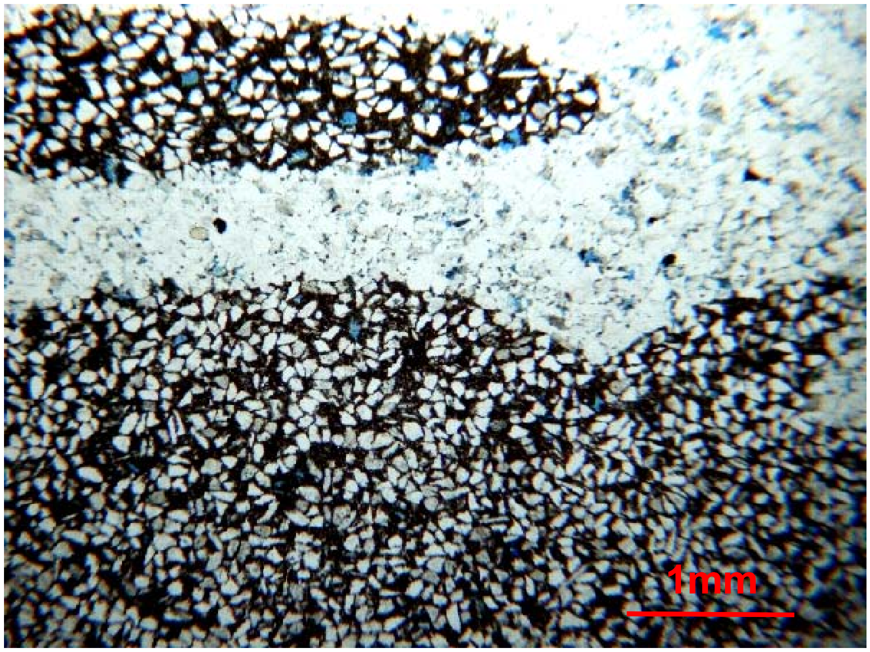


Figure 23a. Clasts of siderite-cemented, fine- to very fine-grained quartz sandstone in a fine- to very fine-grained quartz sandstone from L. S. Hoyt 100 (103-1685) at a depth of 3149.75'; plain light.

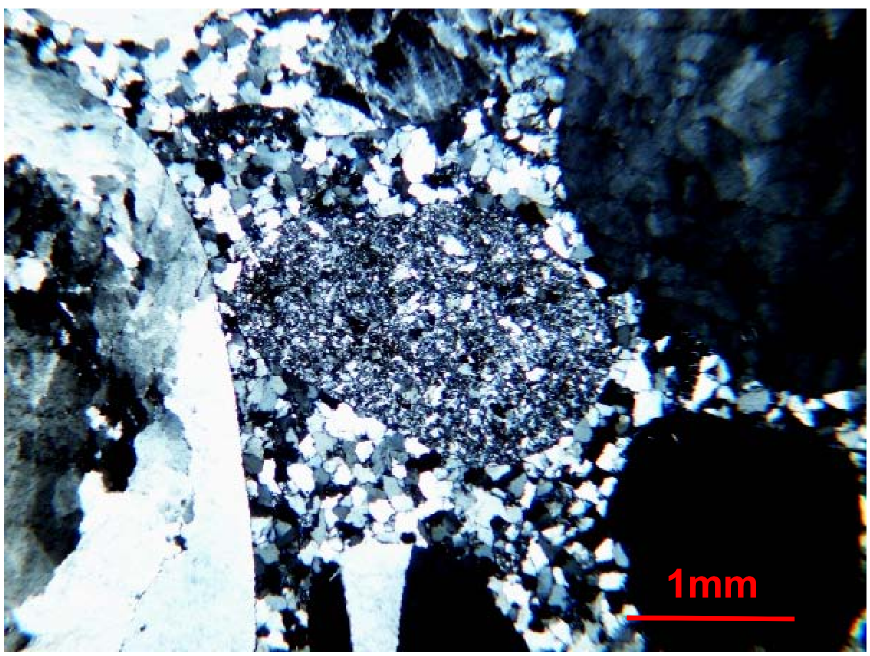


Figure 23b. Well-rounded chert rock fragment in a fine- to very fine-grained quartz sandstone from L. E. Dulaney 10 (103-1171) at a depth of 2852.65'; crossed polars.

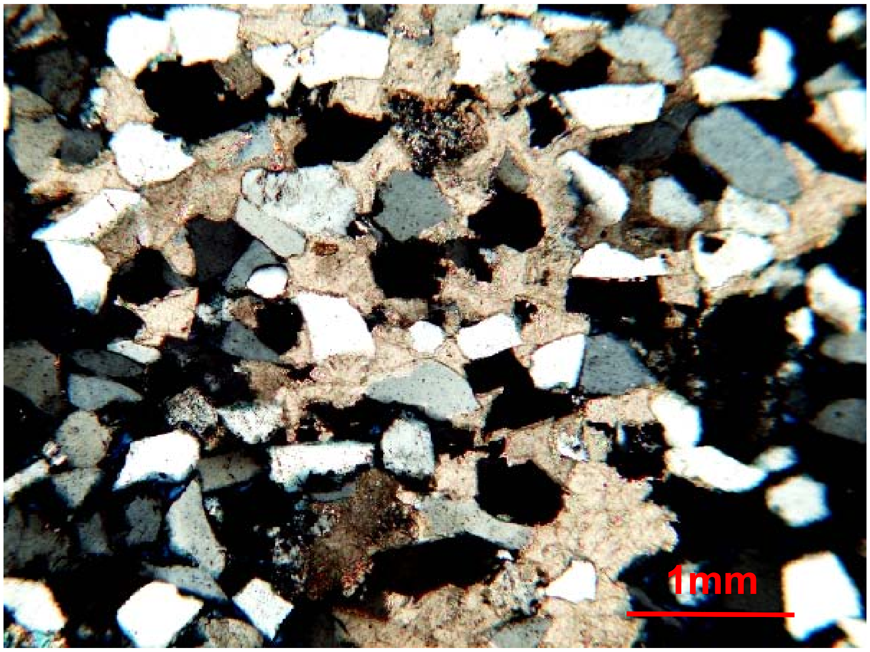


Figure 24a. First-stage, sparry calcite filling pore space in a fine- to very fine-grained quartz sandstone from L. E. Dulaney 10 (103-1171) at a depth of 2857.00'; crossed polars.

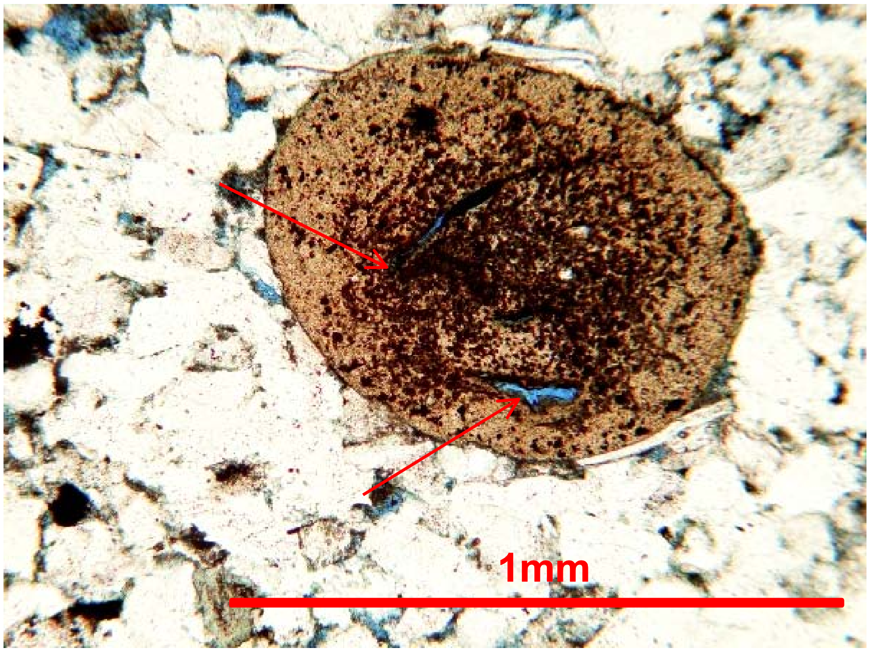


Figure 24b. Phosphatic fecal pellet containing quartz silt and fossil fragments. Secondary porosity (arrows) has developed in voids where calcitic? fossil material has been removed by dissolution. From L. S. Hoyt 100 (103-1685) at a depth of 3137.45'; plain light.

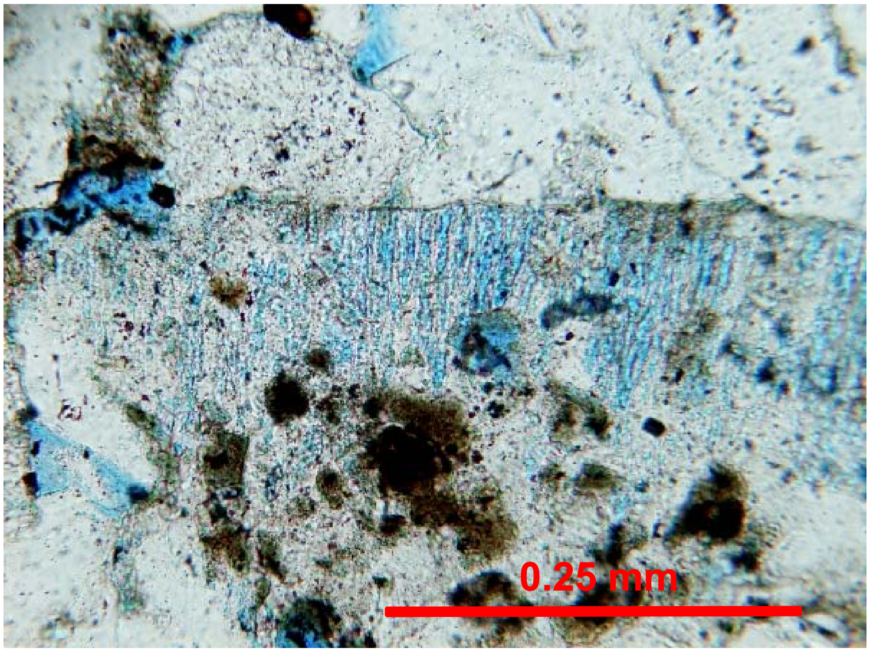


Figure 25a. Highly altered plagioclase grain showing relict twinning. Majority of the grain has been dissolved – secondary porosity is delineated by blue epoxy used to impregnate the rock. From L. E. Dulaney 10 (103-1171) at a depth of 2852.65'; plain light.

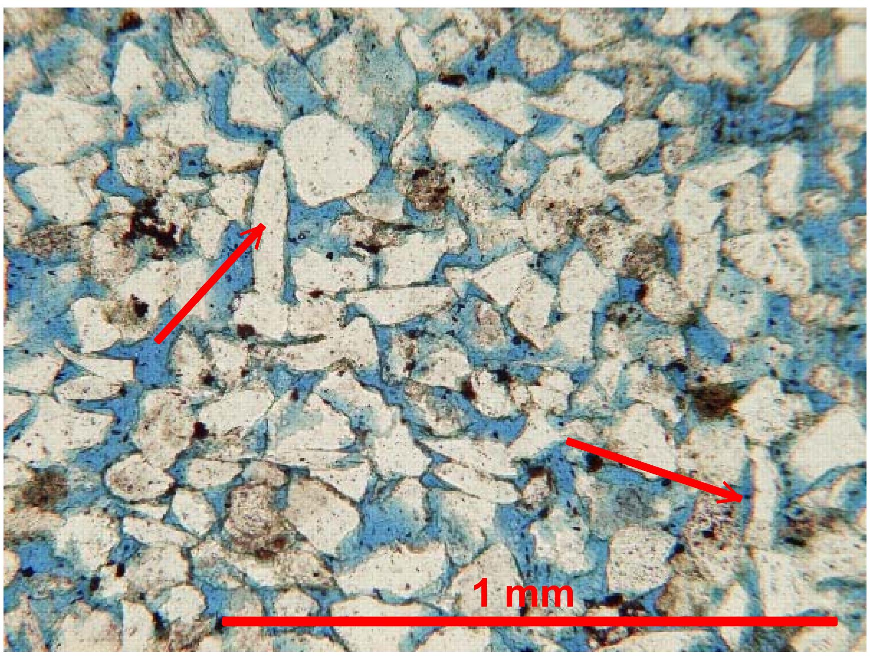


Figure 25b. Elongated quartz grains (arrows) in Featureless sandstone from L. S. Hoyt 100 (103-1685) at a depth of 3148.00'. Bedding is parallel to bar scale. Grains oriented at an angle (90º in this instance) are an indication of bioturbation in sandstones or other sedimentary rocks lacking obvious sedimentary structures.

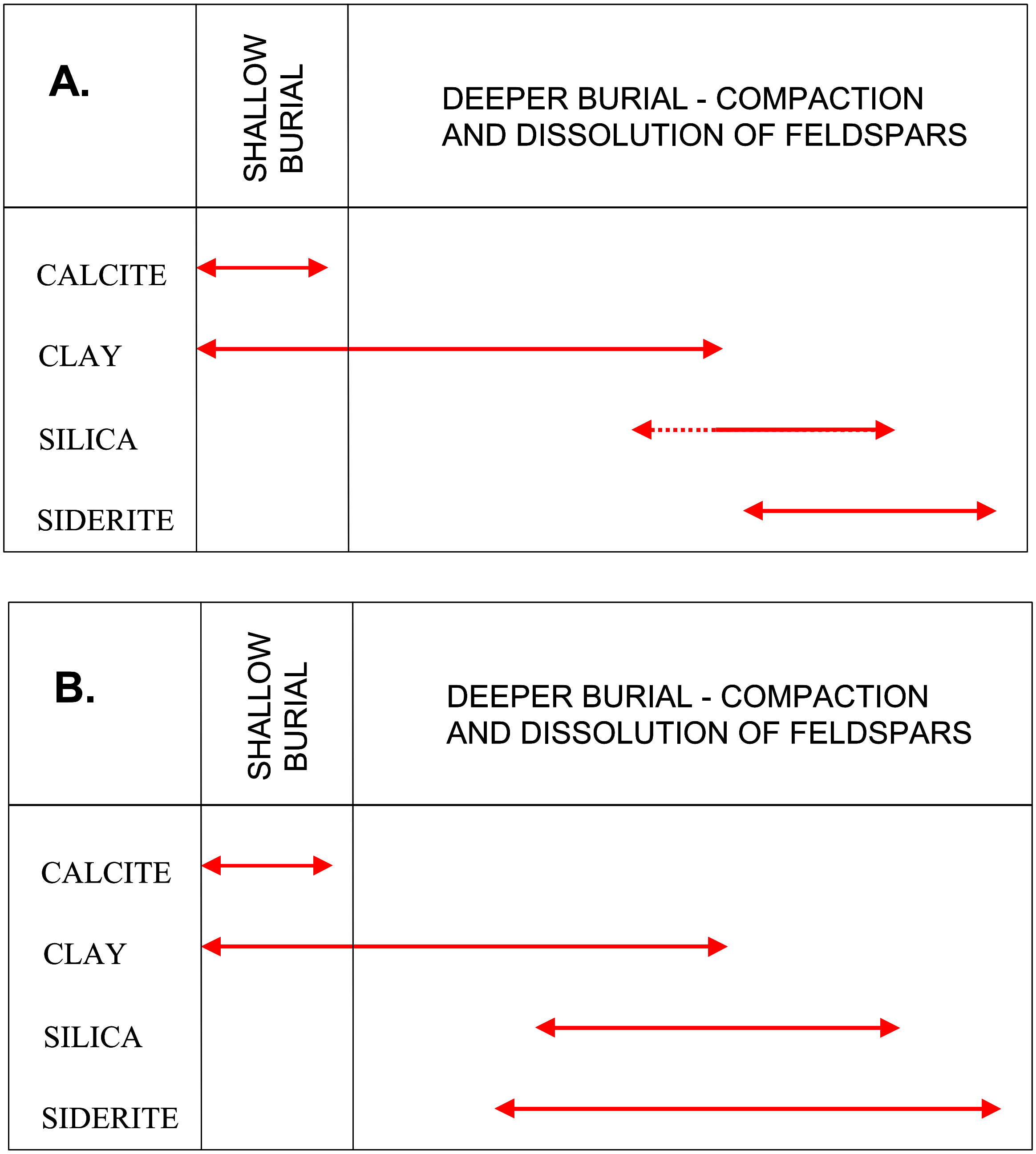


Figure 26. Graphical representation of the timing of cementation in the Gordon sandstone for the Wileyville (A) and Jacksonburg-Stringtown (B) oil fields. In both instances, calcite and clays form the earliest cements, whereas silica and siderite appear later.

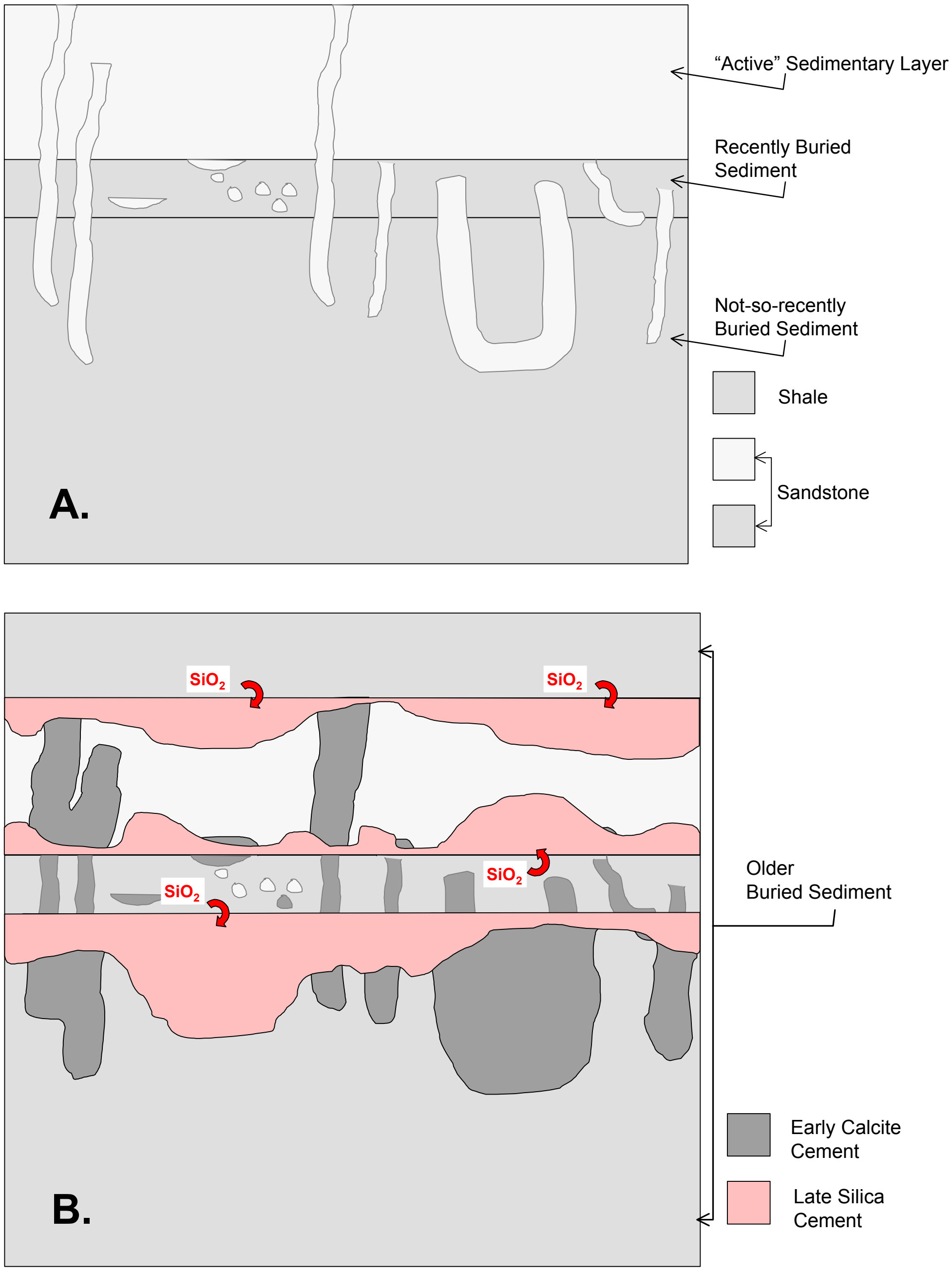


Figure 27. A) Vertical burrows initially allow cementing fluids to migrate between sedimentary layers. These trace fossils are generally concentrated at the tops of beds and are associated with early cementation by calcite. As the density of vertical traces increases, the amount of calcite cementation increases. B) Early calcite cement helps prevents the migration of later cementing fluids between layers of strata. This, in turn, may preserve the permeability within sedimentary layers. *Modified from McDowell and others, 2001.*

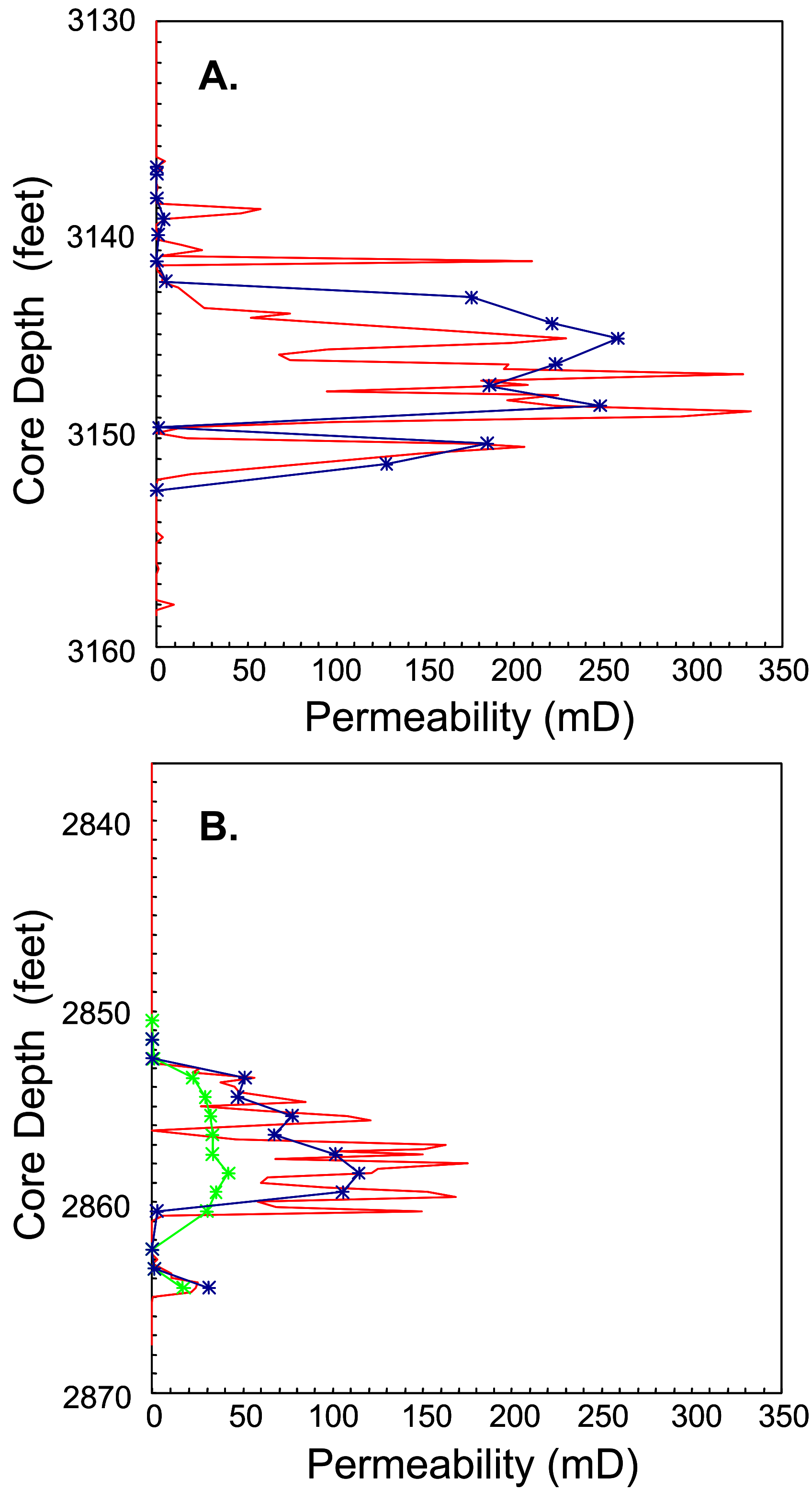


Figure 28. A) Graphical comparison of permeability measured from core plugs (blue) and by minipermeameter (red) for core from L. S. Hoyt 100. B) Graphical comparison of permeability measured from whole core (green), core plugs (blue), and by minipermeameter (red) for core from L. E. Dulaney 10.

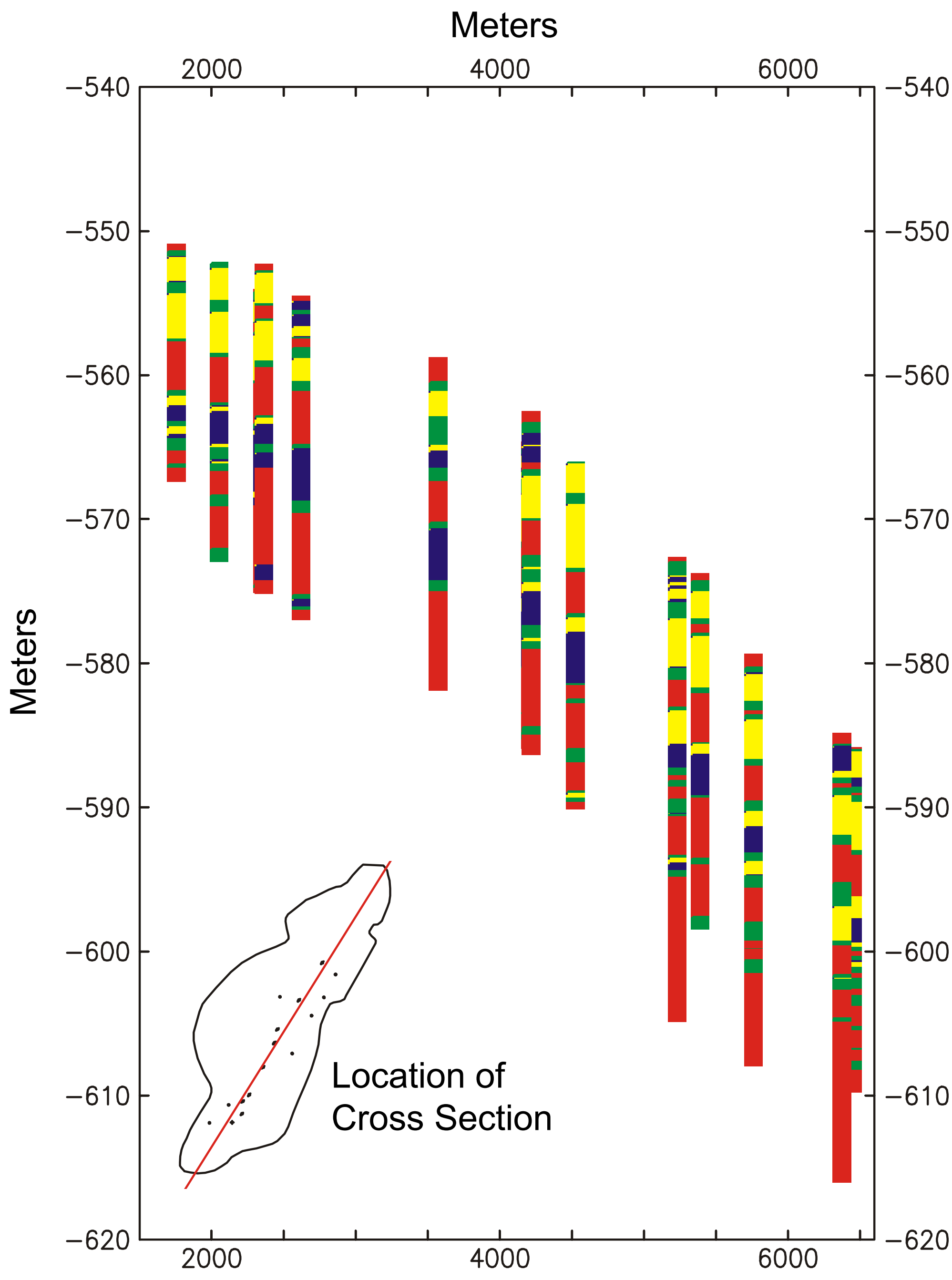


Figure 29. Vertical electrofacies cross section taken along the long axis of the Wileyville oil field – view is to the northwest. Depths and distances between wells are in meters. Wells are placed at their correct subsea elevation; the Gordon interval is observed to deepen to the northeast along the plunge of structure. Color code: Red – Electrofacies 1; Green – Electrofacies 2; Yellow – Electrofacies 3; Blue – Electrofacies 4.

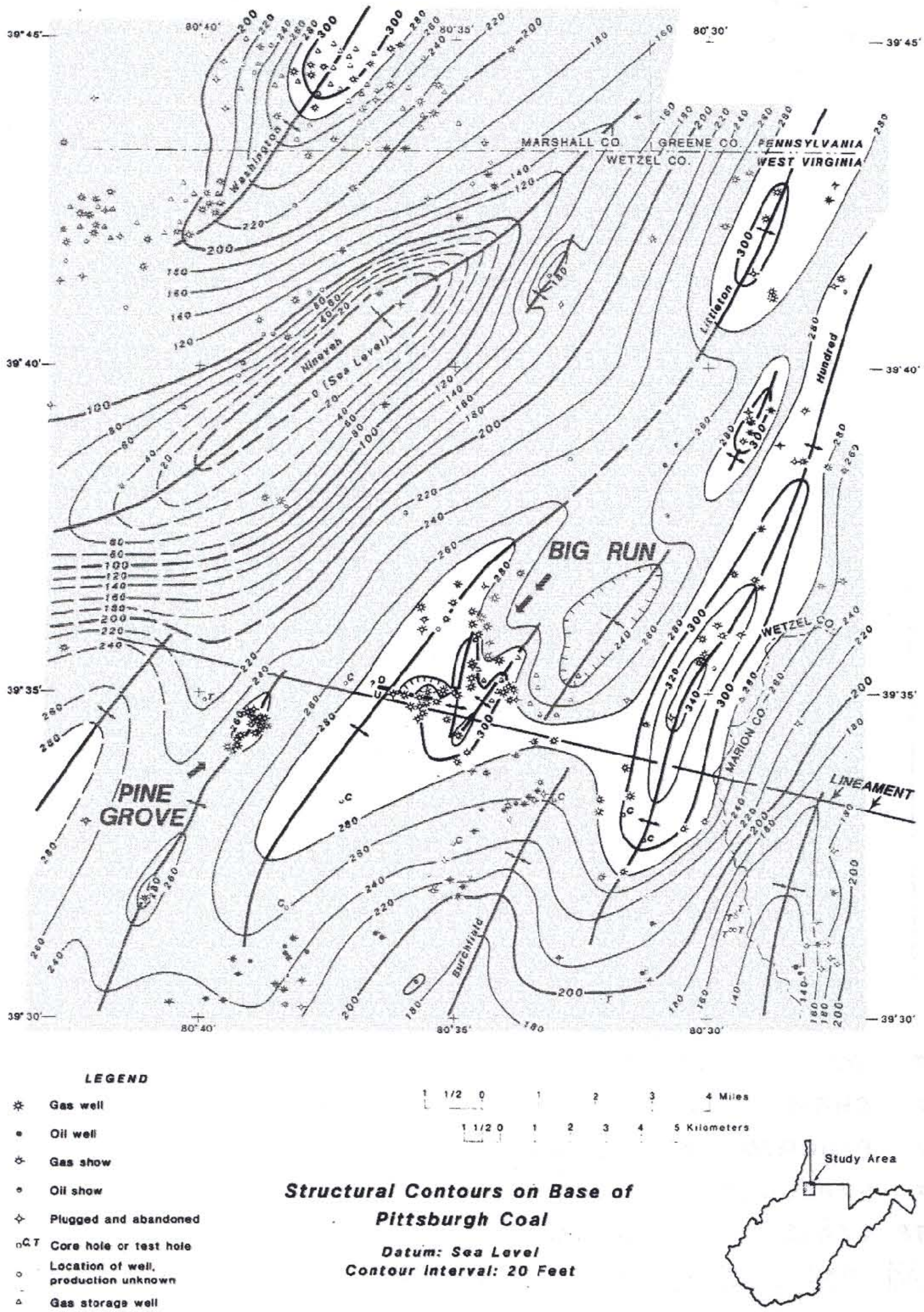


Figure 30. Structural contour map on the base of the Pittsburgh Coal in the Wileyville area. Anticlinal features, gas wells, and wells with gas shows are marked. Areas in which the Pittsburgh Coal may be wet are shaded. ***Modified from Patchen and others, 1991, Fig. 6, p. 14.***

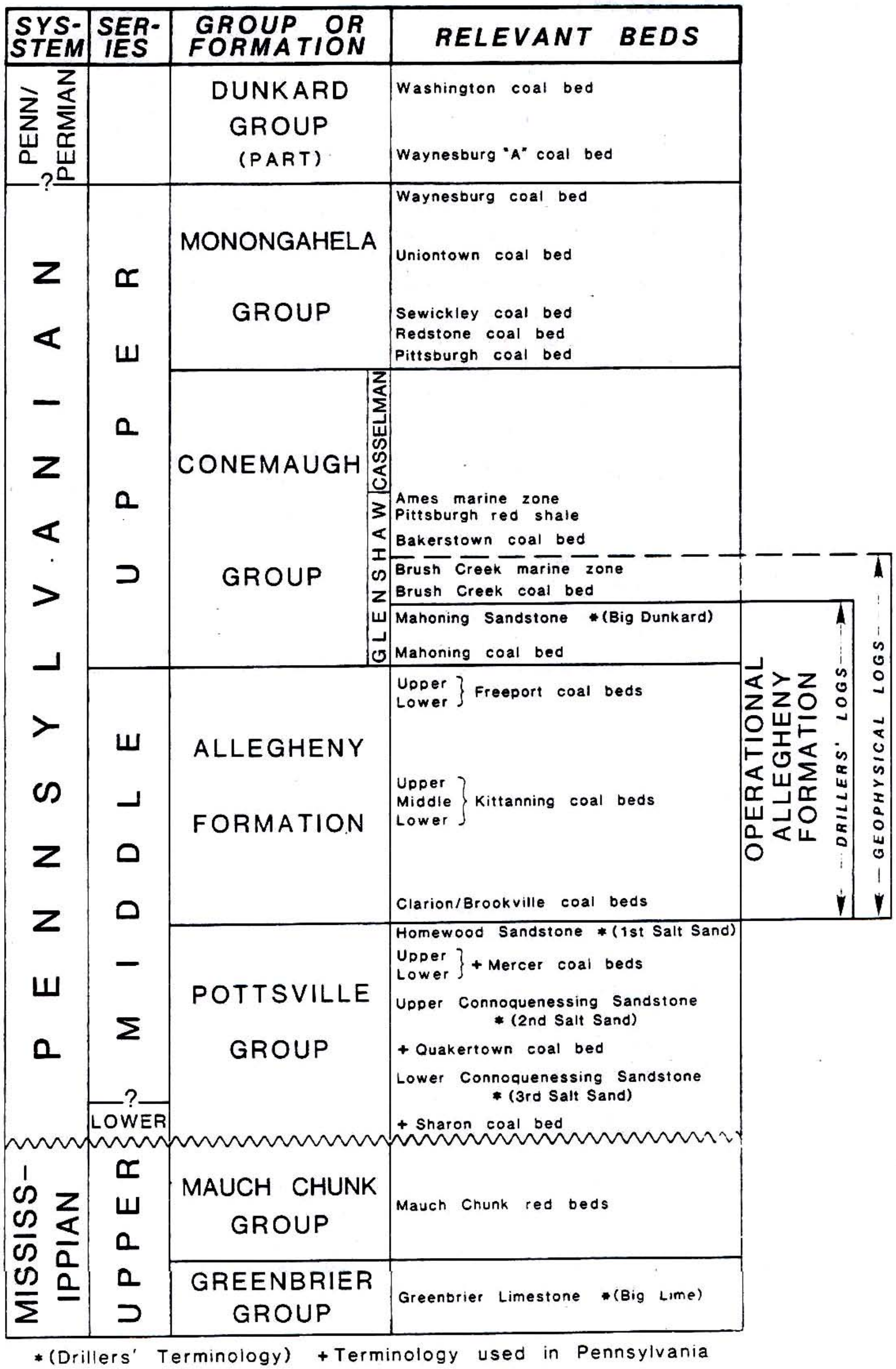


Figure 31. Stratigraphic chart for the uppermost Mississippian and Pennsylvanian in the Wileyville area. Named coal units are listed. ***Modified from Bruner and others, 1995, Fig. 1, p. 2.***

Table 1a. Summary of petrographic analyses of 30 thin sections from the Gordon interval in the Wileyville field. Results for individual lithofacies and the Gordon as a whole are shown.

Facies	Mean Grainsize (mm)	Mean Grainsize (phi)	Monoxtal. Quartz	Polyxtal. Quartz	Sec. Quartz	Feldspar	Primary Porosity	Secondary Porosity	Phyllosilicates	Opaques	Clays	Other
css	1.328770	-0.166434	64.00%	13.08%	7.28%	1.50%	7.08%	0.68%	0.48%	0.15%	2.75%	3.00%
fss	0.126727	2.982198	63.54%	4.13%	0.85%	4.80%	16.33%	1.65%	0.32%	0.21%	6.55%	1.61%
hb	0.155600	2.690119	60.00%	4.00%	13.80%	8.00%	1.15%	2.80%	0.70%	0.35%	6.85%	2.35%
lss	0.177827	3.009967	58.40%	6.73%	8.73%	4.78%	2.89%	0.93%	1.13%	0.46%	4.44%	11.49%
Gordon	0.302740	2.583381	60.97%	6.46%	6.16%	4.58%	7.92%	1.27%	0.74%	0.33%	5.11%	6.46%

Table 1b. Summary of petrographic analyses of 33 thin sections from the Gordon interval in the Jacksonburg-Stringtown field. Results for individual lithofacies and the Gordon as a whole are shown.

Facies	Mean Grainsize (mm)	Mean Grainsize (phi)	Monoxtal. Quartz	Polyxtal. Quartz	Sec. Quartz	Feldspar	Primary Porosity	Secondary Porosity	Phyllosilicates	Opaques	Clays	Other
css	1.363200	-0.288020	60.68%	20.10%	1.96%	1.82%	4.44%	0.66%	0.65%	1.15%	3.90%	4.56%
fss	0.160400	2.734950	60.92%	8.94%	1.32%	3.38%	14.58%	1.80%	1.52%	0.40%	6.08%	0.98%
hb	0.339780	1.859370	61.96%	10.22%	0.40%	2.10%	0.40%	0.32%	0.40%	0.33%	6.11%	17.71%
lss	0.130450	2.961570	62.75%	12.40%	1.90%	3.33%	4.77%	1.48%	2.36%	0.36%	5.46%	5.15%
Gordon	0.540770	1.717320	61.69%	13.55%	1.45%	2.59%	4.95%	0.99%	1.25%	0.59%	5.27%	7.61%

Table 2a. Summary of the petrophysical characteristics of the four Gordon electrofacies in the Wileyville field.

Electrofacies	Mean Gamma Ray	Mean Bulk Density	Mean Permeability	Mean Grainsize
1	122.04	2.70	0.20001	Fine Sand
2	73.34	2.58	10.30922	Very Coarse Sand
3	37.67	2.55	10.15289	Medium sand
4	51.89	2.28	90.70200	Fine Sand

Table 2b. Summary of the petrophysical characteristics of the four Gordon electrofacies in the Jacksonburg-Stringtown field.

Electrofacies	Mean Gamma Ray	Mean Bulk Density	Mean Permeability	Mean Grainsize
1	142.30	2.69	0.00208	Coarse Silt
2	75.28	2.55	1.55785	Fine Sand
3	40.59	2.52	2.66181	Coarse Sand
4	45.85	2.36	30.01643	Medium Sand

Table 3a. Summary of calculations of coal-bed methane potential for the Pittsburgh and Sewickley coals.

	AREA	AREA	COAL THICKNESS	VOLUME	COAL DENSITY[1]	DESORBED GAS[2]	GAS POTENTIAL
	feet^2	acres	feet	acrefeet	tons/acrefoot	ft^3/ton	BCF
Wileyville Field	183720895.10	4217.65					
Pittsburgh_7'	122568095.01	2813.78	7	19696.43			
Pittsburgh_5'	61152800.09	1403.88	5	7019.38			
Pittsburgh_Total	183720895.10			26715.81	1800	150	7.21327
Sewickley_1'	75224512.99	1726.92	1	1726.92			
Sewickley_3'	59055966.42	1355.74	3	4067.22			
Sewickley_5'	49440415.69	1135.00	5	5674.98			
Sewickley_Total	183720895.10			11469.11	1800	150	3.09666
[1] Coal Density from Kelafant and others, 1988, Table 8 - High-volatile Subbituminous Coal							
[2] Desorbed Methane potential from Kelafant and others, 1988, Figure 41 - High-volatile Subbituminous Coal							
at burial depths between 500' and 1000'							

Table 3b. Summary of calculations of coal-bed methane potential for the combined coals of the Allegheny Group.

	AREA	AREA	COAL THICKNESS	VOLUME	COAL DENSITY[1]	DESORBED GAS[2]	GAS POTENTIAL
	feet^2	acres	feet	acrefeet	tons/acrefoot	ft^3/ton	BCF
Wileyville Field	183720895.10	4217.65					
Allegheny_10'	18676487.73	428.75	10	4287.53			
Allegheny_15'	83234004.87	1910.79	15	28661.85			
Allegheny_20'	80348783.03	1844.55	20	36891.08			
Allegheny_25'	1461619.485	33.55	25	838.85			
Allegheny_Total	183720895.10			70679.32	1800	200	25.44455
1 Coal Density from Kelafant and others, 1988, Table 8 - High-volatile Subbituminous Coal							
[2] Supplied by Doug Patchen							

Report Title: A Study to Evaluate the Effect of Cost of Corrosion on Stripper Well Operations

Type of Report: Final Technical Progress Report

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Disclaimer

Abstract

A prior study performed for the Department of Energy yielded the fact that the largest problem contributing to abnormal production decline in stripper gas wells was due to fluid accumulation in the wellbore. Furthermore, the study identified that mechanical failures accounted for 23% of the problems contributing to abnormal production decline. Mechanical failures are generally corrosion related to the surface or downhole equipment. This study proposes to develop methodologies including decision trees and a procedure guide to identify the most effective technologies for corrosion mitigation for stripper wells. The application of systematic methodologies and techniques will increase the efficiency of problem assessment and implementation of corrective measures to minimize the effects of corrosion on stripper wells. Effective corrosion mitigation and treatment methods for stripper wells will benefit every producer by increasing production and ultimate recoveries since it is one of the most common problems leading to production decline.

Field research will be conducted on several hundred wells in Ohio available to James Engineering, Inc. to identify critical factors affecting rates of corrosion and the methods currently employed to mitigate the effects of corrosion. Specifically, wells previously identified as experiencing mechanical failure will be reviewed in addition to those where no corrosion has been observed. Previous methods of corrosion mitigation and repair will be investigated. As a result of the field research, a decision tree and procedure guide will be prepared to help operators mitigate the effects of corrosion on stripper well production performance. The field research will attempt to determine when a particular type of corrosion treatment method is effective.

The culmination of this study developed a procedure guide detailing potential areas of corrosion, their causes, and cost effective corrosion mitigation and repair procedures. A summary of the results of the study was presented at the joint meeting of the AAPG and SPE at the Eastern Regional Meeting in Pittsburgh, Pennsylvania on September 9, 2003.

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List of Graphical Materials

Table 1	None

Introduction

A prior study performed for the Department of Energy yielded the surprising fact that the largest problem contributing to abnormal production decline in stripper gas wells was due to fluid accumulation in the wellbore. Furthermore, mechanical failures were identified as accounting for 23% of the problems contributing to abnormal production decline. Mechanical failures are generally corrosion related to surface or downhole equipment. This study proposes to develop methodologies including decision trees and a procedure guide to identify the most effective technologies for corrosion mitigation for stripper wells. The application of systematic methodologies and techniques will increase the efficiency of problem assessment and implementation of corrective measures to minimize the effects of corrosion on stripper wells. Effective corrosion mitigation and treatment methods for stripper wells will benefit every producer by increasing production and ultimate recoveries since it is one of the most common problems leading to production decline.

Field research was conducted on hundreds of wells in Ohio available to James Engineering, Inc. to identify critical factors affecting rates of corrosion and the methods currently employed. Specifically, wells that were identified in the previous study as experiencing mechanical failure were reviewed in addition to wells where little or no corrosion had been observed. Previous methods of corrosion mitigation and repair were also investigated. As a result of the field research, a procedure guide and decision trees were prepared to help operators mitigate the effects of corrosion on the production performance of stripper wells. The field research assisted in determining when a particular type of corrosion treatment method was effective.

The culmination of this study resulted in the development of an application guide detailing potential areas of corrosion and cost effective corrosion mitigation procedures. This final technical report reviews summarizes the procedure guide and the Society of Petroleum Engineers paper prepared and presented at the Eastern Regional Meeting on September 9th in Pittsburgh, Pennsylvania. Both the procedure guide and the SPE paper are presented in their entirety in the Appendix of this report.

Executive Summary

A prior study performed for the Department of Energy yielded the surprising fact that the largest problem contributing to abnormal production decline in stripper gas wells was due to wellbore fluid accumulation. Furthermore, mechanical failures were identified as accounting for 23% of the problems contributing to abnormal production decline. Mechanical failures were in generally corrosion related in the surface or downhole equipment. This study proposes to develop methodologies including decision trees and a procedure guide to identify the most effective technologies for corrosion mitigation for stripper wells. The application of systematic methodologies and techniques will increase the efficiency of problem assessment and implementation of corrective measures to minimize the effects of corrosion on stripper wells. Effective corrosion mitigation and treatment methods for stripper wells will benefit every producer by increasing production and ultimate recoveries since it is one of the most common problems leading to production decline.

Field research was conducted on hundreds of wells in Ohio available to James Engineering, Inc. identifying critical factors affecting rates of corrosion and the methods currently employed. Specifically, wells that were identified in the previous study as experiencing mechanical failure were reviewed in addition to wells where little or no corrosion has been observed. Previous methods of corrosion mitigation and repairs were investigated. As a result of the field research, an application guide and decision trees were prepared to help operators mitigate the effects of corrosion on the production performance of stripper wells. The field research assisted in determining when a particular type of corrosion treatment method was effective.

This final technical report summarizes the procedure guide and the Society of Petroleum Engineers paper prepared and presented at the Eastern Regional Meeting on September 9th in Pittsburgh, Pennsylvania. The procedure guide initially provides a section with sufficient detailed information for the corrosion novice to gain a basic understanding of the mechanism of corrosion. The second section provides simplified step-by-step instruction for those operators who just want to get started. Additional information includes a quick corrosion summary list, a decision tree for total corrosion mitigation plan development, and corrosion field review data collection sheets. A quick summary is provided on corrosion related to production casing, tubing, wellheads, separators, production tanks, gas gathering systems, and production lines. Each of the specific corrosion areas presents a brief general discussion, identifies common corrosion areas, corrosion identification methods, corrosion repair methods, corrosion mitigation methods, and the decision trees and procedures available. The guide also includes a corrosion definitions section, recommended websites for corrosion information, vendor links for information on corrosion related items, recommended sources of information, and a paint information section. The procedure guide and the SPE paper are presented in their entirety in the Appendix of this report.

Experimental Apparatus and Operating Data

No experimental methods, materials, or equipment were used in this phase of the research.

Results and Discussion

The specific steps to develop the methodology of this study and completed as proposed included:

- Literature Search of Appropriate Application of Corrosion Mitigation Methodologies for Stripper Wells
- Develop Data Collection Forms for Field Review
- Perform Field Review of Critical Areas Affected by Corrosion
    - Production Storage Tanks
    - Wellheads
    - Pipelines
    - Downhole Tubulars
- Summarize Results of Field Review of Areas Affected by Corrosion
- Develop Decision Tree to Select Appropriate Corrosion Mitigation Technology
- Test Decision Tree
- Prepare Application Guide Detailing Cost Effective Corrosion Mitigation Technologies
- Prepare Technical Paper and Transfer the Technology

The detailed results of each step to develop the methodology can be found in the quarterly reports, the procedure guide, or the SPE paper. In lieu of presenting each of the detail associated with the individual steps, the summaries, procedure guide, and SPE paper are present instead in this final report. Therefore, this final technical report briefly summarizes the procedure guide and the Society of Petroleum Engineers paper prepared and presented at the Eastern Regional Meeting on September 9th in Pittsburgh, Pennsylvania. The procedure guide and the SPE paper are presented in their entirety in the Appendix of this report.

I. Procedure Guide

The ultimate goal of the study was the development of the procedure guide. Per the original proposal, "An application guide will be prepared to assist operators in determining appropriate corrosion mitigation treatment by evaluating the current treatment methodologies of specific wells to minimize corrosion."

Data Reduction and Methodology

A procedure guide was developed that incorporates the results of the study into logical, step-by-step procedures for mitigating corrosion by the specific components associated with stripper wells. The components, which were divided by section in the procedure guide, include production casing, tubing, wellheads, separators and production units, production tanks, and gathering lines and production lines. Each component section provides a general discussion, then identifies common corrosion areas, corrosion identification methods, corrosion repair methods, corrosion mitigation methods, and the decision trees and procedures applicable to the particular component.

The procedure guide first provides an introduction to corrosion that includes: Corrosion Defined, Components of Corrosion, Types of Corrosion, Primary Agents of Corrosion, The Importance of Ohm's Law, Soil Resistivity Defined, Soil Resistivity Measurement, Potential Measurements, Corrosion Identification Methods, Corrosion Identification Instrumentation, Cathodic Protection Design Factors, Common Methods of Corrosion Control, Corrosion Economics, and Corrosion Training.

However, some operators may want to simply just get started, the procedure guide allows operators to skip the introduction to corrosion, although recommended reading, to begin the their fight against corrosion in the section entitled ***"Where to Begin".*** This section begins with a brief introduction then provides a Quick Corrosion Summary List to quickly highlight where corrosion occurs and provide some corrosion mitigation methods. The guide then provides a "Decision Tree Form For Total Corrosion Mitigation Plan Development" to allow operators to develop their own corrosion mitigation program. Data collection forms are provided as Corrosion Field Review Data Collection Sheets for operators to use in evaluating then incorporating each well, facility, or pipeline into a corrosion mitigation plan. As previously discussed, individual sections are provided for each main stripper well component affected by corrosion.

Other procedure guide highlights include Decision Trees and Repair procedures for tubing and casing leaks due to corrosion, Decision Tree For Production Storage Tanks Corrosion Mitigation and a Plastic Tank Summary. Other highlights of the guide include Gathering System Identification and Review Steps, a Decision Tree Form For Pipeline or Production Line Leak, Pipeline Rehabilitation by Sliplining with Polyethylene Pipe, Plastic Pipe Pressure Rating Guidelines, a form for Pipeline Inspection or Leak Report, a method for Estimating Anode Requirements for Bare pipe or Hot Spot Protection, a few Pipeline Coating Repair Procedures. Further, the Appendix in the guide includes Abbreviations and Definitions, Recommended Web Sites for Corrosion Information, Vendor Links for Information on Corrosion Related Products, Recommended Sources of Information, and Paint Information and Guidelines.

Overall, the procedure guide provides an understanding of corrosion and a review – prioritization methodology. Review - prioritization considerations include identifying: high value wells and gathering systems, corrosion mitigation methods, corrosion correction methods, associated costs, previous corrosion areas, desired facility life, environmentally sensitive areas, significant potential for harm wells, i.e. H2S wells, and/or wells located in well-populated areas. While the overall subject of corrosion is complex, in most cases the process of corrosion mitigation can be simplified for stripper well operators to the proper application of planning, painting, and plastic.

II. SPE Paper - Society of Petroleum Engineer's Eastern Regional Meeting Presentation

Data Reduction and Methodology

A technical paper based upon the results of the study was presented at the Society of Petroleum Engineer's Eastern Regional Meeting in Pittsburgh, Pennsylvania September 9, 2003. The paper summarizes the overall study and the individual steps leading to the development of the procedure guide. The paper as it was presented is provided in the appendix.

III. Conclusion and Future Work

Corrosion affects every stripper well to some degree and if left unchecked results in the repair or replacement of casing, rods, tubing, separators, production tanks, and pipelines. Additional effects include lost or deferred production, lower equipment salvage values, environmental damage and associated penalties, and decreased safety.

The costs associated with corrosion, while substantial can be managed best when considered as a cost of doing business. Proper planning utilizing the decision trees and procedures presented in the procedure guide should significantly reduce the amount of time and expense that would otherwise be required for addressing corrosion related issues.

Stripper well operators face multiple challenges, cannot afford to utilize the same corrosion control methods as major transmission and natural gas storage companies, but still require economic, efficient, easy to use techniques for corrosion mitigation.

Stripper well operators should develop in-house expertise through education, and training through the West Virginia University Appalachian Underground Corrosion Short Course. It is important that stripper well operators employ consistent methodologies that includes an equipment database, cost estimates, economic prioritization, an annual budget, scheduled maintenance, documentation, and monitoring when planning to effectively mitigate the effects of corrosion.

While the process of corrosion is complex and often misunderstood, it is largely controllable. Primary cementing of production casing over H_2S or coal bearing zones or chemical inhibition should eliminate most downhole casing problems. Regular maintenance through surface preparation, painting, and leak correction would eliminate many wellhead and tank related problems. Proper tank setting and bottom coating would significantly reduce most tank bottom corrosion related incidents. Utilizing plastic tanks for salt-water storage would eliminate most of the problems associated with steel tanks. Finally, coated pipe, cathodic protection, hot spot protection, and the use of plastic for pipeline replacement would significantly reduce many pipeline corrosion problems.

Ultimately, rather than randomly addressing corrosion, a thoughtful review and appraisal of current corrosion related problems then incorporated into a formal plan to mitigate corrosion should make a positive economic impact on the overall cost of operations for most stripper well operators. Simply stated, the proper application of planning, painting, and plastic can achieve great results in stripper well operations.

This concludes "The Study to Evaluate the Effect of Cost of Corrosion on Stripper Well Operations."

References:

Not Applicable.

Bibliography:

Not applicable

List of Acronyms and Abbreviations:

Not applicable.

Appendices
Procedure Guide
SPE Paper

Practical Guide to Identify, Repair, and Prevent Corrosion in Stripper Well Operations

Stripper Well Consortium

SWC Award Number: 2283-JE-DOE-1025

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A. Introduction

This procedure guide was prepared as a result of research completed through a joint venture between James Engineering, Inc. and the United States Department of Energy's Stripper Well Consortium program. The goal of the research was to develop a procedure guide detailing cost effective corrosion mitigation methods for stripper wells. The final technical report of this research and SPE paper number 84835 should be reviewed for a complete description of the methodologies, results, and conclusions utilized in developing this procedure guide.

A previous study completed by James Engineering, Inc. showed that 270 of 376 wells evaluated, or over 70%, exhibited some form of abnormal production decline within the past five years. Nearly 50% of the abnormal production declines was due to liquid loading, or fluid accumulation in the wellbore while over 20% of the declines were due to corrosion. The effects of corrosion resulted in both decreased reserves and revenue. However, the nature of corrosion represents a significant opportunity for improvement since the cause appears correctable through the proper application of corrosion mitigation techniques.

The petroleum industry spends millions of dollars every year developing new oil and natural gas reserves and yet additional millions are spent maintaining existing production facilities from the effects of corrosion. The National Association for Corrosion Engineers estimates that the total annual corrosion expenditures for all United States industries combined is $300,000,000,000 while the onshore oil and gas industry alone has annual expenditures exceeding $300,000,000 combating corrosion. Further, it has been estimated that the effects of corrosion are so extensive that the replacement of corrosion damaged materials accounts for approximately 20% of the annual iron produced in the United States.

The oil and natural gas industry has historically observed the effects of corrosion throughout all phases of production operations and considerable strides have been made to understand not only the process of corrosion but also develop methods to mitigate its effects. However, due to the limited income associated with stripper oil and gas wells, many operators often cannot afford to implement the level of corrosion control methods utilized by major natural gas transmission and storage companies. Therefore, this procedure guide was prepared to provide practical methods of corrosion control for the stripper oil and gas well utilizing cost effective methods to not only identify but also mitigate the effects of corrosion.

Information utilized in the preparation of the guide was based upon experience, repair procedure review, field review of existing wells, well file review, significant literature searches on corrosion mitigation, and interviews with well tenders interviews, producers, oilfield supply representatives, and corrosion product representatives.

The following discussion and terminology provides a basis for the methodologies developed for stripper well operators to address corrosion by first defining corrosion, then reviewing the components of corrosion, the electrochemical nature of corrosion, the various types of corrosion, discuss soil resistivity and its effects on corrosion, corrosion identification methods, corrosion control methods, and finally review the decision trees and associated procedures developed to assist stripper well operators. While an understanding of the mechanism and forms of corrosion can lead to an understanding of the proper means for controlling corrosion, for those who desire to just get started turn to the section entitled "Where to Begin" on page 18. Note that this guide is not intended to be a comprehensive text on the complex subject of corrosion.

B. Corrosion Defined - Corrosion is typically defined as "*the deterioration of a material, usually a metal, due to a reaction with its environment.*" The energy absorbed and stored during conversion from raw ore to finished metal product through refining and fabricating is later released by corrosion as metals seek a less energized state. The required conversion energy varies for each metal - relatively high for magnesium and relatively low for silver. It has been well documented that the greater the conversion energy required, the greater the potential for corrosion. Table 1 shows the conversion energy required for some commonly used metals.

The "corrosion potential" of various metals has been measured in volts then placed in a table called the "galvanic series" by order of their tendency to corrode from the most corrosive (most active or anodic), to the least corrosive (most noble or cathodic), see Table 2.

Table 1. Positions of some metals in descending order of energy required to convert their ores to metals. The greater the required conversion energy, the greater the corrosion potential

	Chemical
Most Energy Required	Potassium
	Magnesium
	Beryllium
	Aluminum
	Zinc
	Chromium
	Iron
	Nickel
	Tin
	Copper
	Silver
	Platinum
Least Energy Required	Gold

The energy difference between metals and their ores can be expressed in electrical terms which are related to heats of formation of the compounds.

Table 2. Practical galvanic series of metals, ranked from most to least corrosive

	Metal	Volts
Progressively More Anodic and More Corrosive	Pure Magnesium	–1.75
	Magnesium Alloy Mix	–1.60
	Zinc	–1.10
	Aluminum Alloy (5% Zinc)	–1.05
	Pure Aluminum	–0.80
	Mild Steel (clean and shiny)	–0.5 to 0.8
	Mild Steel Rusted	–0.2 to 0.5
	Cast Iron	–0.5
	Lead	–0.5
Progressively More Cathodic and Least Corrosive	Mild Steel in Concrete	–0.2
	Copper, Brass, Bronze	–0.2
	High Silicon Cast Iron	–0.2
	Mill Scale on Steel	–0.2

C. Components of Corrosion – or, What does it take for corrosion to occur? Rust, while commonplace to the naked eye, is the result of very complex electrochemical reactions. The electrochemical reactions are related to the flow of electricity and to the chemical interactions between the metal and the surrounding soil. Further, the amount of electricity generated is directly related to the amount of metal being removed. The chemical reactions are a function of the soil type and it's moisture characteristics.

In order for corrosion to occur, there must be four components; an anode, a cathode, a metal path connecting the anode and cathode, and an electrolyte that surrounds the anode and cathode. When all four of the components are combined a "corrosion cell" is created causing electrical current to flow and metal to be consumed. Conversely, corrosion will cease if any one of the four components are removed.

To further define the four components, the anode is the metal electrode in contact with the electrolyte where corrosion occurs, electrons lost, metal dissolved, and current leaves the metal and enters the electrolyte. The cathode is the metal electrode in contact with the electrolyte where no corrosion occurs, electrons gained, rust deposits occur, and current is picked up. The metal path connecting the anode and the cathode is where the electrons flow. The electrolyte is a solution or conducting medium such as soil containing water, oxygen, or dissolved chemicals where metal ions and current flow. Figure 1 below shows a common battery corrosion cell where electrons flow from the negative electrode (*anode*) through the wire and light bulb (*metal path*) to the positive electrode (*cathode*), and ions flow from the positive electrode through the sulfuric acid (*electrolyte*) to the negative electrode.

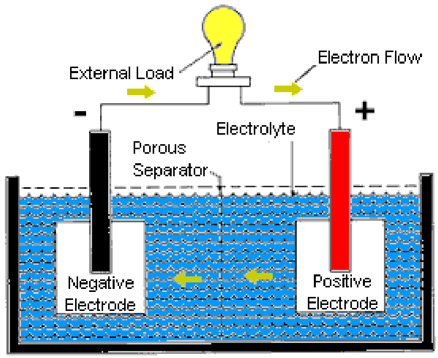
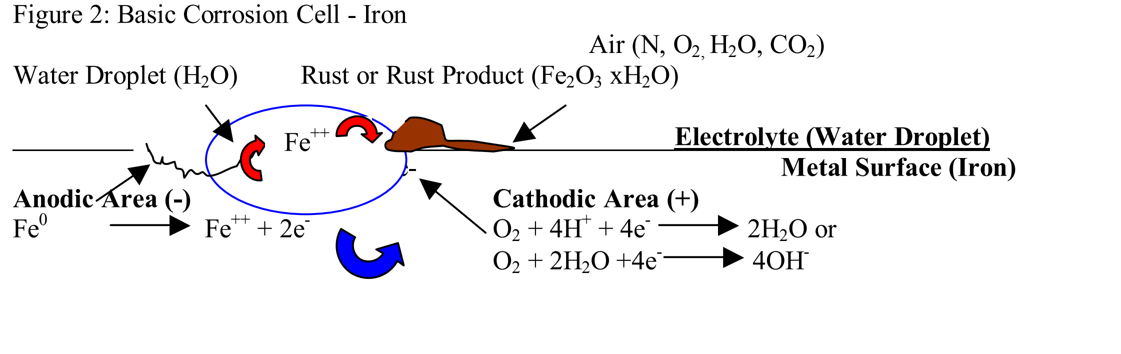


Figure 1 - Components of a Battery Cell (Discharge Circuit)

While figure 1 identifies the anode and cathode as two separate entities, they are often a part of the same piece of metal. Refining and fabricating create individual steel grains variances within the same piece of metal that make them anodic or cathodic to one another. The variances are further enhanced by varying environmental, soil conditions, and pipeline coating inconsistencies. Therefore the electrodes may be a fraction of an inch apart or they may be miles apart.

Figure 2 shows the chemical reactions for a corrosion cell in a single piece of steel. Metal loss begins to occur at an anodic area as atoms of iron, Fe^0, go into solution as Fe^{++} ions in the electrolyte (water droplet), or $Fe^0 \rightarrow Fe^{++} + 2e^-$. Corrosion slows as Fe^{++} ions accumulate near the anode surface until precipitated as rust product (Fe_2O_3 x H_2O) due to the presence of oxygen thus allowing the corrosion process to continue. The electrons, e^-, released from the atoms of iron flow through the metal path creating electricity until their charge is neutralized through chemical reduction with hydrogen or oxygen; or $O_2 + 4H^+ + 4e^- \rightarrow 2\ H2O$ or $O_2 + 2H_2O + 4e^- \rightarrow 4OH$.

Figure 2: Basic Corrosion Cell - Iron



Note: the essential difference between ordinary steel and pure iron is the amount of carbon in the steel: low carbon 0.3%, medium 0.3 – 0.6%, high 0.6 – 1.0%, and ultra high 1.25 – 2.0%.

In summary, corrosion is the release of the refining and fabricating energy required to convert iron ore (iron oxide) into steel leaving the steel in a higher energy state with a natural tendency to return to its lower energy state of native iron ore as iron oxide or rust

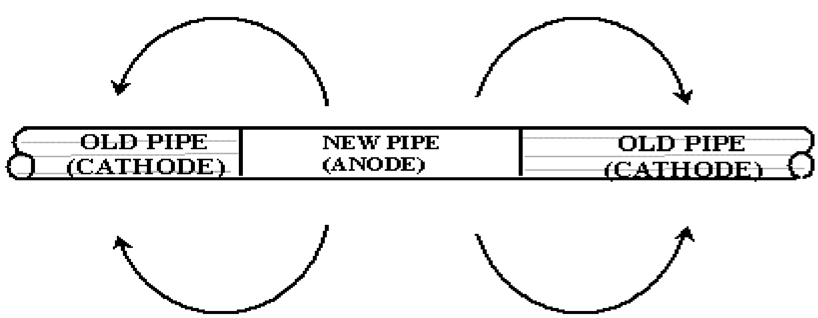
D. Types of Corrosion - Because corrosion categories vary according to specific industries, for the purposes of our study, corrosion was divided into two fundamental types: general and localized. General corrosion is characterized by a uniform layer of corrosion or metal loss, with no pitting, and is generally a very slow process. Localized corrosion can be aggressive and was further categorized as galvanic, pitting, crevice, inter-granular, stray current, microbiologically induced, de-alloying, erosion, and stress.

Galvanic corrosion occurs due to the potential difference between two materials. Pitting corrosion is evidenced by trough shaped cavities over a small area with rust covering most pits. Crevice corrosion occurs due to changes in the local chemistry in shielded areas under gaskets, washers, insulation material, fastener heads, surface deposits, disbonded coatings, lap joints, and clamps. Intergranular corrosion is localized attack along or immediately adjacent to the grain boundaries to grain boundaries while the bulk of the grains remain largely unaffected. Stray current corrosion is very aggressive and occurs when an unprotected line crosses a line protected by impressed current. Microbiologically induced corrosion (MIC) is initiated by the presence of microorganisms, bacteria (aerobic or anaerobic), or fungi and results in pitting and crevice corrosion. Oil transport lines and waterflood operations often have to address MIC. Erosion corrosion is generally associated with turbulent flow of fast moving fluids is also associated with the rubbing action of sucker rods against tubing walls. De-alloying and stress corrosion (associated with materials in deeper wells) are generally not factors in stripper well operations.

Differential corrosion cells are created by the following: differential aeration of compacted compared to un-compacted soil, mill scale corrosion of where pipe steel is anodic to mill scale, new pipe anodic to old pipe, dissimilar soils or soil conditions, and the relative size of the anodic to the cathodic area.

A new steel section with no rust on it becomes anodic to the rest of the existing rust coated pipeline and corrosion on the new steel is accelerated, see figure below.

Example of New Pipe to Old Pipe Galvanic Corrosion
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



E. Primary Agents of Corrosion - Moisture content, oxygen, carbon dioxide, hydrogen sulfide, chlorides, temperature, pH, environment, and physical effects are the primary agents of oilfield corrosion. The rate of corrosion increases as the concentration of any of these factors increases, with the exception of ph. Corroding agents often work together resulting in a “synergistic effect” to further increase corrosion rates.

First, without moisture, corrosion would not occur. Corrosion is minimized in arid environments like the desert due to decreased moisture content, but is greatly enhanced in humid, moist, or wet environments. Eliminating and/or reducing moisture contact is essential to minimizing corrosion and is accomplished through enclosures, coverings, coatings, and the elimination of leaks. Small leaks over time are very detrimental and should be quickly repaired.

Oxygen is one of the most common corrosion agents affecting all equipment due to its ready availability and its tendency to form metal oxides. Buried structures are also impacted by variations in oxygen content due to soil differences such as clay vs. sandy, hard rock vs. silty, or compacted vs. uncompacted. Relatively oxygen poor compacted soil (anodic area) at the bottom of the pipe causes current to flow to the relatively oxygen rich less compacted soil (cathodic area) at the top of the pipe. Painting, coating, and cathodic protection are generally effective measures against oxygen-enhanced corrosion.

Carbon dioxide and hydrogen sulfide gases are most often associated with specific reservoirs or geographic areas and their presence can be anticipated and planned for. Material selection, primary cementing, chemical inhibitors, painting, or scrubbers are effective at combating H_2S and CO_2. H_2S reacts readily with iron in the presence of water and results in the precipitation of iron sulfide, a black porous substance cathodic to iron.
The increased chlorides associated with oilfield brines accelerate corrosion rates due to increased conductivity. Storage tank bottoms are especially susceptible to corrosion due to varying water levels from rain and snow when combined with oxygen and released brine, therefore, it is important to minimize any brine leakage inside the tank dike.

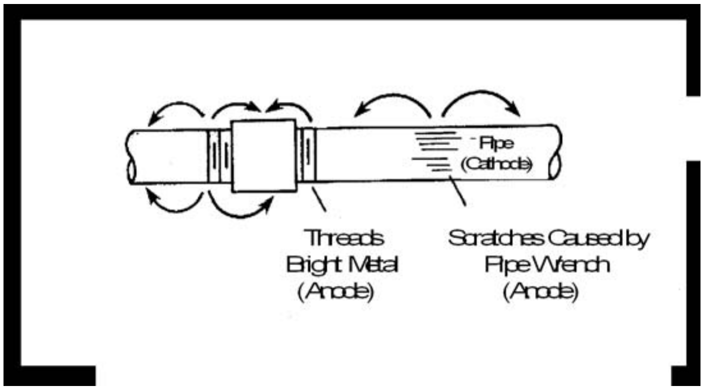
Increased temperature increases the surface rates of corrosion while decreased temperature slows corrosion dramatically after all soil moisture is frozen. Therefore, corrosion cells are much more active in the summer than in the winter especially where temperatures drop below freezing.

PH is calculated as a negative logarithm of the concentration of hydrogen ions, where a ph of 7 or greater is basic or alkaline, 7 neutral, and less than 7 acidic. Relatively, below 4.5 is extremely acidic while greater than 9.0 is very strongly alkaline. Each increment of ph represents a ten-fold increases in ph since pH is measured logarithmically, for example from 5 to 6. Acidic conditions are conducive to corrosion, therefore, environmental conditions affect ph, especially in those areas where acid rain is a problem.

Physical problems that increase the potential for corrosion include mill scale, tool marks, gouges, nicks, and bite marks from pipe wrenches on steel surfaces that expose bright metal. The “bright metal” surfaces become anodic to the adjacent cathodic metal, for example field cut threads, which should be coated with spray paint. Cold working metal (field bending) and welding introduce residual stresses that make the material susceptible to stress corrosion cracking. See example of field cut threads and pipe wrench marks below.

Well tenders and roustabouts trained in corrosion identification can assist operators in mitigating corrosion through early recognition in determining proper corrosion mitigation methods.

Examples of anodic areas caused by bright metal thread and wrench mark scratches Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



F. The Importance of Ohm's Law: I = E / R

Ohm's Law defines the relationship between corrosion, current, voltage, and resistance where the current (I) in amperes equals the voltage differential between anode and cathode (E), divided by the resistance of the entire circuit (R). ***The amount of current generated is directly proportional to the rate of metal loss or corrosion at the anode, i.e., the greater the current flow in the corrosion circuit, the greater the metal loss.*** One ampere of direct current discharging into a typical soil can remove approximately twenty pounds of steel in one year, or 20 pounds per ampere-year. While metal consumption rates are expressed in pounds per ampere per year, most currents measured are only thousandths of an ampere, or milli-amperes.

G. Soil Resistivity Defined

Soil resistivity, the reciprocal of conductivity, is the accepted industry standard as the primary indicator of soil corrosivity, and is measured in ohm centimeters, or ohm-cm. The lower the resistivity, the easier current flows through the soil. Soils with resistivities below 1000 ohm-m can cause severe pipeline deterioration. Soil resistivity is defined by the equation: ρ, the resistivity of the soil in ohm centimeters, equals 2 times Π (3.1416) times A, the soil cross sectional area, times R, the resistance of the soil sample in ohms.

Soil is comprised of solids, a combination of stones, gravel, silt, and clay, and voids filled with liquids and gases (electrolytes). Soil resistivity, a function of the soil solids and the voids, is specifically related to the soil type or composition, moisture content, acidity, salt content, oxygen, bacteria, and temperature. Soils with measured resistivities greater than 50,000 ohm-cm are mildly corrosive; 30,000 to 50,000 ohm-cm are moderately corrosive, and less than 30,000 ohm-cm are very corrosive. Table 2 summarizes soil resistivity as a function of the soil type.

Moisture helps chemicals in the soil surrounding pipelines to carry electrical current. The higher the moisture content, the lower the soil's resistivity. Moisture content of ~16% is required for oxidation and reduction to occur. For example, sandy loam with 2.5 moisture content has a resistivity of ~1,500 ohm-m, while at 15% moisture content the resistivity drops to 105 ohm-m. Soils with high organic content have low resistivities, higher moisture levels, and higher electrolyte levels. Sandy soils drain faster, have lower moisture content, lower electrolyte level, and higher resistivity. Solid rock contains virtually no moisture or electrolytes and has very high resistivity levels.

Table 2 Soil Resistivity as a Function of Soil Type		
Soil Type	**Ohm – Cm**	**Corrosion Level**
Poorly graded gravels	100,000 – 250,000	Negligible
Well graded gravels	60,000 – 100,000	Mildly Corrosive
Clayey gravel	20,000 – 40,000	Moderate
Silty sands	10,000 – 50,000	Severe to Moderate
Clayey sands	5,000 – 20,000	Severe to Moderate
Fine sandy or silty soils	8,000 – 30,000	Severe to Moderate
Silty or clayey fine sands	3,000 – 8,000	Severe
Gravelly clays	2,500 – 6,000	Severe
Inorganic clays	1,000 – 5,500	Severe
Sand	90 – 8,000	Severe
Marshy ground, Loam	2 – 150	Very Severe

Similar to chlorides (brines) in water, chlorides in soil accelerate corrosion, through increased conductivity thereby significantly reducing resistivity. For example, sandy loam with 15.2% moisture content at 0% salt is 107 ohm-m, while at 20% salt is only 1 ohm-m; both readings represent severe corrosion potential. Again, small leaks over time are very detrimental.

Resistivity increases substantially when moisture content falls below 10% or temperatures fall below freezing. For example, sandy loam with 15% moisture at 60° Farenheight has a 72 ohm-m resistivity, while at 14° F has a 3,300 ohm-m reading.

H. Soil Resistivity Measurement - Soil resistivity measurements provide a direct indication of the corrosive properties of soil. Measurements of soil resistivity variations along a given pipeline route help predict potential areas of corrosion. For example, pipeline sections in low resistivity soils become anodic and corrode relative to those sections in higher resistivity soils. The most common field soil resistivity measurement methods include the Wenner four-pin method (the most accurate), the three-pin method (variation in-depth method), and the copper-copper sulfate reference electrode, or CSE method. Laboratory testing of samples obtained through drilling or excavation operations may be performed to assess soil resistivities.

The Wenner four-pin method (ASTM G-57) and the three-pin method measure the average resistivity of large volumes of soil based on the spacing of the measuring pins. The resultant resistivity is the average resistivity of the soil (electrolyte) to a depth equal to the spacing between adjacent electrodes (soil pins). The maximum depth (pin spacing) of this standard test set has been designed for 20 feet, which is recommended for standard survey. Four pins are driven into the ground in a straight line with each being spaced a distance x from the next. The distance between pins is equal to the depth measured. AC current is then passed between the two outer pins while voltage between the two inner pins is measured. Voltage is measured with the AC on and off, and the difference of the voltages, ΔV, determined. The resistance between the inner pins is $R = \Delta V$ times I, where I is the applied AC current. Measurements should be made perpendicular to a pipeline and no closer than ten feet to the pipe. Readings are typically taken every 100 - 400 feet over the length of pipeline by a two to three man crew.

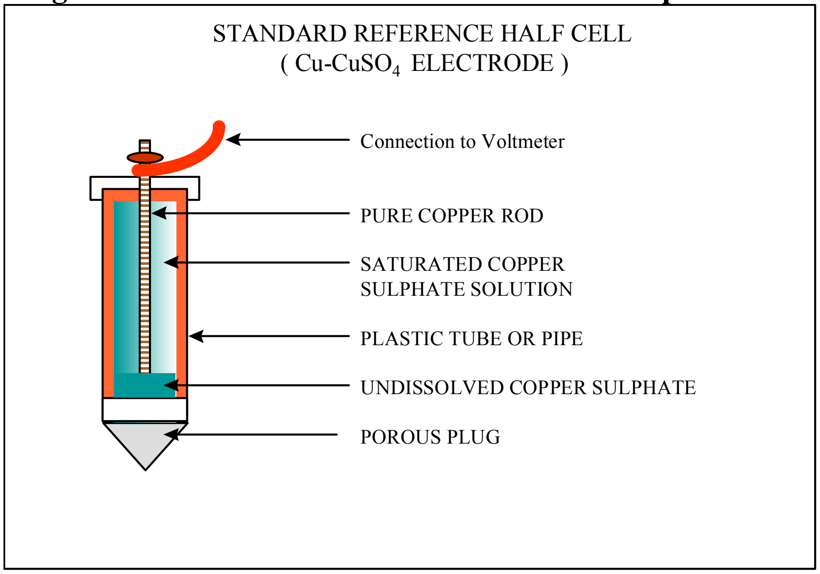
I. Potential Measurements

Potential measurements, pipe to soil or soil to soil, are used to identify extent of metal corrosion, cathodic protection, stray currents, and hot spots. Measurements are accomplished using test stations, copper–copper sulfate electrodes, and voltmeters. Typical sign convention is that reactive metals are negative and noble metals are positive. *More negative readings along a pipeline indicate a hot spot or an increase in corrosion potential.*

The copper–copper sulfate electrode or CSE method measures a small volume of soil in the area surrounding the tip of the rod. The positive terminal of the voltmeter is connected to the CSE reference electrode and the negative terminal to the pipeline, tank, or other structure. Pipe to soil potentials are generally negative under corrosive conditions when measured with a CSE. Digital meters, rather than analog, are recommended due to their ease of use and resistance to damage if polarity is reversed. See example of copper-to-copper sulfate electrode below

The main use of metal to soil measurements is to determine whether a pipeline has sufficient cathodic protection (positive lead to pipe, negative lead to CSE, digital meter set to DC). A pipeline with –850 millivolts along most points is considered to be cathodically protected when measured with a CSE. Rust build-up over time on older non-protected lines make it less likely to corrode and metal to soil measurements taken over time would become less negative. A newly laid, coated pipeline may have a pipe-to-soil potential of -500 to -700 millivolts while an old bare pipeline may be –100 to –300 millivolts.

Example of copper-copper sulfate electrode, CSE
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems

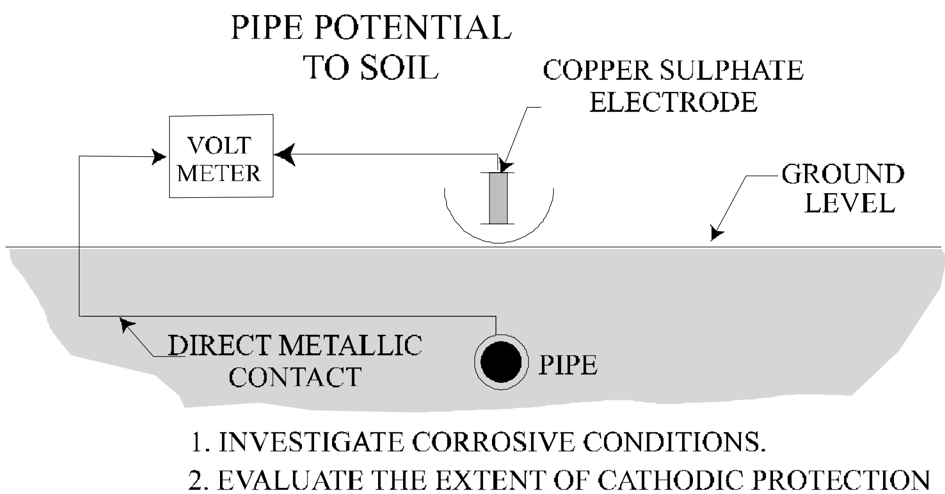


Permanent test stations provide a means for determining soil and pipe conditions instead of utilizing portable “stations”. It is recommended that stripper well operators consider installing permanent test stations to monitor pipeline corrosion even when no cp or coatings are utilized. Stations should be installed at a maximum intervals of one every half-mile. This type of survey utilizes the pipe as the 'reference' against which the ground potentials are measured. The voltage will decrease if a coating fault exists as the portable meter half-cell is moved towards the fault. See example of potential test below.

Resistivity readings can be shifted up to one volt by scrap batteries, buried tools, welding rods, farm implements and parts, abandoned 'foreign' services, abandoned concrete bases, disused welding tips, and natural unidentified features.

Stripper well operators usually find contracted services that conduct soil resistivity measurements cost prohibitive. The general condition of most gathering system right of ways, un-mowed and unmarked, increase the time required for soil resistivity surveys who are unfamiliar with operator systems. An estimated cost for a contracted three-man soil survey crew for one mile is approximately $1,000 per day. However, in-house personnel with nominal training and investment for equipment can complete soil resistivities.

Example of pipe potential to soil test using copper-copper sulfate electrode CSE
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



J. Corrosion Identification Methods - Corrosion identification methods include visual inspection, physical observation, pressure and production monitoring, electronic inspection, soil analysis, fluid analysis, chemical analysis, corrosometer electrical resistance (E/R) measurement, hydrogen probes, and metal coupon analysis.

Visual inspections are limited to external surfaces but are beneficial to stripper well operations due to the low cost and general effectiveness. Visual inspections identify potential problems with wellheads, exposed sections of casing and tubing, separators, production units, meters, storage tanks, and surface lines. Well tenders or production managers should complete visual inspections for prioritizing maintenance, repairs, or replacements.

Physical observation identifies mechanical failure due to corrosion resulting in the loss of pressure and product from wellheads, tanks, or pipelines. Well tenders, landowners, and production variance reports assist in identifying mechanical failures. Physical observation identifies corrosion resulting in the loss of pressure and product in wellheads, tanks, or pipelines. Well tenders, landowners, and production variance reports assist in identifying mechanical failures. Physical signs of a natural gas leak include an odor, a hissing sound, dirt or water being blown into the air, bubbling in wet areas, patches of dead vegetation, fire burning above the ground, dry spots in moist fields, areas of abnormally hard or dry soil, or a white vapor cloud close to the ground. Oil spills are generally identified as seepages or as rainbow sheens.

Well tenders often identify mechanical failures through monitoring operating pressures and production volumes. Decreases in normal operating pressures may indicate a casing or pipeline failure while decreases in gas production or increases in fluid production often indicate a casing failure. Loss of fluid from a tank noted during tank gauging or normal gas production without normal fluid production may indicate a leak at the bottom of a tank.

Electronic inspection allows for the review of the internal surfaces of production casing and pipelines. Electronic methods include radiographic examinations (x-ray), ultrasonic devices, electromagnetic inspection, caliper surveys, and measuring electric current in casing. Large production companies, gas transmission companies, or natural storage companies utilize electronic logging to regularly monitor casing and pipelines. Regular monitoring identifies pitting or general corrosion so that corrective action can be taken prior to catastrophic mechanical failure. These will typically indicate the specific location of any potential area and then classify it as either a class 1, 2, or 3. Stripper well operators generally rely on more cost effective methods of prevention or repair, rather than incur the expense of periodic electronic inspection.

Electronic identification equipment used by stripper well operators includes portable gas detectors, pipeline locators, gps units, and portable gas analyzers. Electronic gas detectors identify gas leaks even when an odor is not perceived. Pipeline locators identify the location of steel pipelines and the tracer lines installed with plastic pipelines. Global positioning satellite or gps units are very affordable and user friendly for use in identifying pipeline routes, and well and leak locations. Data from gps units can be easily downloaded to relatively inexpensive topographic mapping software such as Terrain Navigator for printing seamless maps. Portable gas detectors assist in determining the presence of H_2S or CO_2. An H_2S concentration of 250 ppm or more and ph of 6.5 or less indicates a corrosive environment, while for CO_2, a 7-psi partial pressure with a ph of 7 or less and a count of 100 ppm or greater indicates a corrosive environment. Cathodic protection cannot prevent hydrogen embrittlement.

Soil resistivity analysis, previously discussed, identifies the conductivity of the soil to determine the potential corrosivity. This testing can be accomplished in-house with some training by stripper well operators and is generally too expensive to contract out to experienced companies.

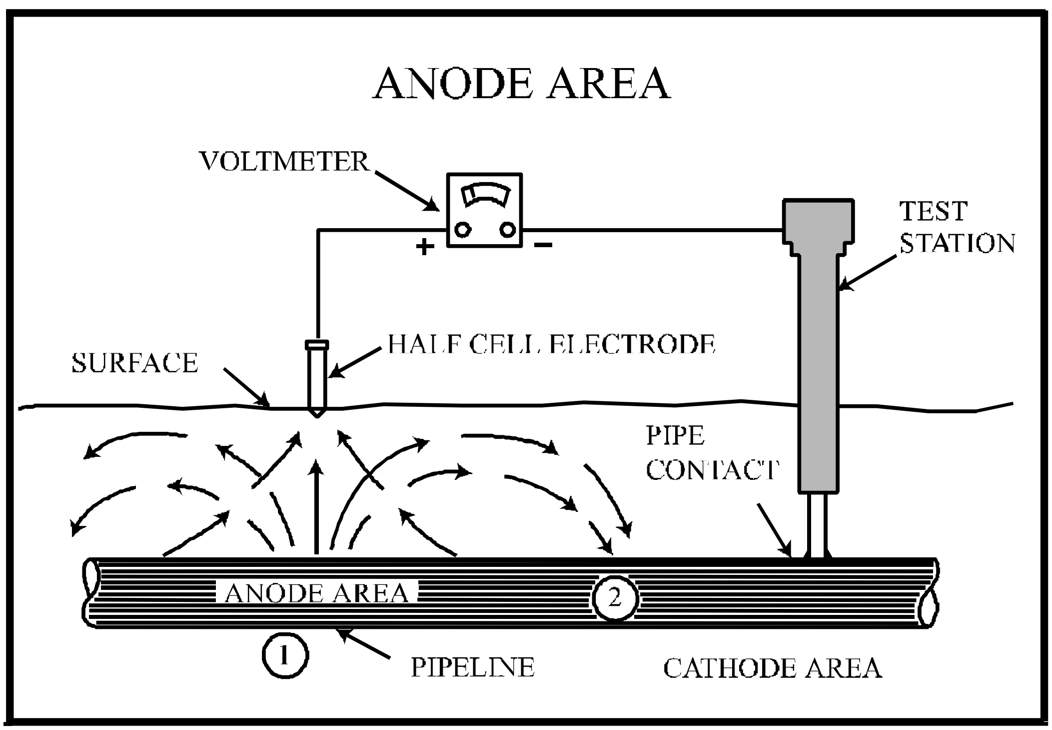
Pipe-to-soil and soil-to-soil potential measurements can be taken with copper-to-copper sulfate electrodes to identify corrosive environments. Roustabouts and technicians can be trained to utilize the equipment associated with these measurements.

Chemical analysis, performed by trained oilfield chemical company personnel, identifies potentially corrosive elements in a production stream. Specifically, chemical analysis is used to identify the presence and concentrations of iron, sodium, potassium, calcium, magnesium, chlorides, sulfates, carbonates, resistivity, hydrogen sulfide, pH, and total dissolved solids. The increased concentration of these factors generally increases the corrosive environment with the exception of ph. Continuous monitoring of fluids is required for water floods due to the interaction of injected water and reservoir fluids.

Ph measurements can be measured in the field or sent to the laboratory for analysis. Ph is the negative logarithm of the hydrogen ion calculated in powers of 10, that is, a solution with a ph of 1.0 is 10 times greater than one with a ph of 2.0. Significant corrosion is unlikely in alkaline water or soils with ph values of 7 or higher while any ph of 6 or less provides an environment for significant corrosion and probable pitting.

Corrosion coupons identify internal pipeline corrosion and quantify the metal loss in millimeters per year, mils per year, or MPY. Pre-weighed coupons are put in line, left for one month to one year, removed, and then analyzed. Coupons are photographed, cleaned, visually inspected, dried, re-weighed, and re-photographed. The corrosion rate is then estimated based upon the weight of coupon material lost. Champion Technologies recommend that a coupon test of less than 5 MPY and no pitting indicates corrosion is unlikely, less than 5 MPY with pitting indicates isolated corrosion, while greater than 5 MPY indicates active corrosion. Further, the most frequent causes of pipeline internal corrosion are improper welding, too high or low of velocity, inadequate pigging leading to scale or paraffin buildup, liquid buildup, bacteria growth, or use of the wrong inhibitor.

Example of typical test station
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



Common corrosion areas identified in the study that stripper well operators should concentrate on includes un-cemented H2S bearing zones, top joints of either tubing or casing near the packing, all leaking connections, unlined metal salt water storage tanks, heater tube areas, bottom of oil and brine storage tanks, and bare pipelines in moist areas. Further, it is important for operators to be able to differentiate between corrosion that looks bad and corrosion that requires immediate attention. Company employees can receive corrosion training through the Appalachian Underground Corrosion School held in May of every year in Morgantown, West Virginia.

Documenting all analyses, visual identifications, observations, and leak repairs will assist in the mitigation of future mechanical failures. The records provide vital information regarding past performance and current conditions.

K. Corrosion Identification Instrumentation - The instrumentation utilized in the identification and analysis of pipeline corrosion include voltmeters, multi-meters, soil resistivity test instruments, wall thickness gages, pit gages, current interrupters, pulse generators, pulse analyzers, pipe locators, cable locators, ammeter clamps, insulator checkers, test rectifiers, holiday detectors, reference electrodes, coupons, portable power supplies, wire reels, portable shunts, soil resistivity pins, magnetic flux leakage, ultrasonic, x-ray, and soil resistivity boxes. Companies that typically utilize most of the previously mentioned instruments are those engaged in the corrosion business, large oil and gas operators, or transportation or storage companies with corrosion departments. Most major oil field supply companies have a complete line of corrosion related products, but may not have the technical expertise to provide advise on specific operator requirements.

One company, Corrosion Control Products Company, (800) 421-2623, offers twenty different product groups with 220 corrosion related products. General product areas include Cable Locators, Metal Detectors, Leak Detectors, Level Indicators, Non-Destructive Dry Film Thickness Gauges, Destructive Paint Inspection & Thickness Gauges, Certified Coating Thickness Calibration Standards, Wet Film Thickness Gauges, Ultrasonic Thickness Gauges, Holiday Detectors, Coating Surface & Contamination Testers – 8, Temperature & Humidity Measurement – 7, Surface Moisture Meters, Coating Adhesion Testers, Miscellaneous Coating Equipment & Accessories, Pipeline Coatings, Protective Coatings, Heat Shrinkable Products, Flange insulation Kits, Insulation Unions and Fittings (300 and 3000 psi), Casing Seals and Insulators, Rock Shields , Pipeline Pigs, and Corrosion Control Accessories.

L. Cathodic Protection (cp) Design Factors: Stripper well operators should carefully consider the following design factors: risk, length of line, operating pressure of system (plastic versus steel), life of project (coated steel versus non coated), resistivities of soil, availability of electric power, existence of other DC power sources, measurement of existing pipe to soil potentials using standard half cell, current demands, resistance to earth of the anodes, quantity and location of anode or anode systems, electrical supply requirements, test and monitoring facilities. Other considerations include landowner issues, public authorities, ground bed easements, cables, transformer rectifier sites, and electricity supplies.

Experience indicates that stripper oil and gas operators can generally achieve good success utilizing either plastic pipe, or a combination of coated pipe and sacrificial anode system for protecting most small diameter (2” – 4”), low-pressure (5 – 250 psi) gas gathering systems. Larger diameter (>4”), high pressure systems (>250 psi) should be reviewed for the relative benefits of utilizing impressed current over the sacrificial anode system. Existing systems without coating or cp will benefit by the application of hot spot protection during repairs or replacements.

Stripper well operators need to determine what is an acceptable risk when reviewing corrosion mitigation strategies, with risk defined as the likelihood of failure times the consequences of failure. The determination of relative risk based upon the safety, environmental, and financial liabilities associated with each facility will assist stripper well operators in prioritizing corrosion mitigation procedures.

M. Common Methods of Corrosion Control

The goal of corrosion control should be to facilitate operation of the wells, maintain mechanical integrity, and protect the overall investment. A corrosion control program should not be one that simply manages failures and leaks, but one that incorporates cathodic protection, protective coatings, material selection - corrosion resistant materials, insulating joints, chemical inhibitors, and environment control. Note that any corrosion control method implemented on an existing structure will not “repair” current damage, but will arrest further damage to the structure.

Note: Chapter three on corrosion control from the US Department of Transportation Guidance Manual for Operators of Small Natural Gas Systems contains a simplified description of the corrosion control requirements contained in the pipeline safety regulations. This section does a great job identifying and explaining the various corrosion control methods generally applicable to stripper well operators for natural gas gathering systems and should also be reviewed. The manual is generally free upon request.

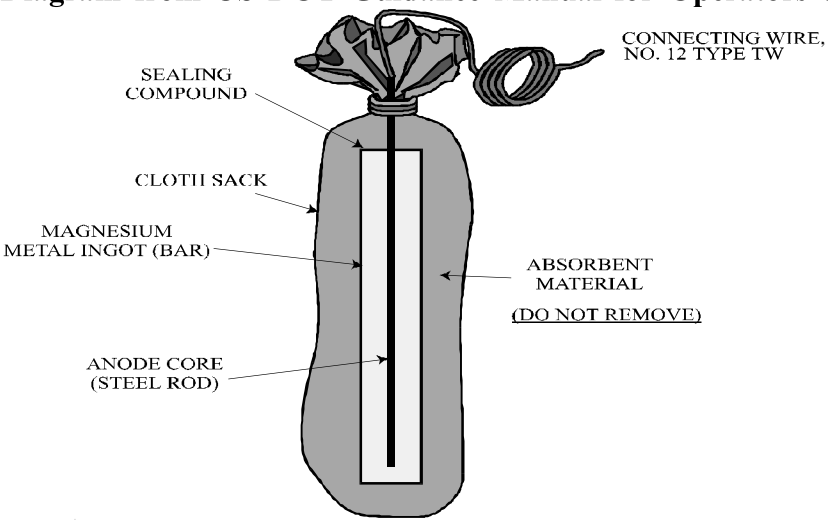
Corrosion protection is achieved when the corrosion current equals zero either by the application of a perfect, no holiday coating which is not possible, or by making the difference between the anode and cathode voltage equal to zero through the application of cathodic protection.

Cathodic Protection, cp, was first utilized in 1824 when Sir Davy attached zinc plates to the copper sheathing on British naval vessel hulls to retard the corrosion. The cp process uses direct current from an external source to oppose the discharge of current from anodic areas by making pipelines or storage tanks the cathode in the electrochemical cell. Without cp, current flows from pipeline anodic areas into the surrounding soil causing the pipeline to corrode. Cathodic protection does not eliminate corrosion but directs it at a less costly, expendable, replaceable, material. Cathodic protection for protecting pipeline systems is generally achieved by utilizing sacrificial anodes and rectifier ground bed or impressed current systems.

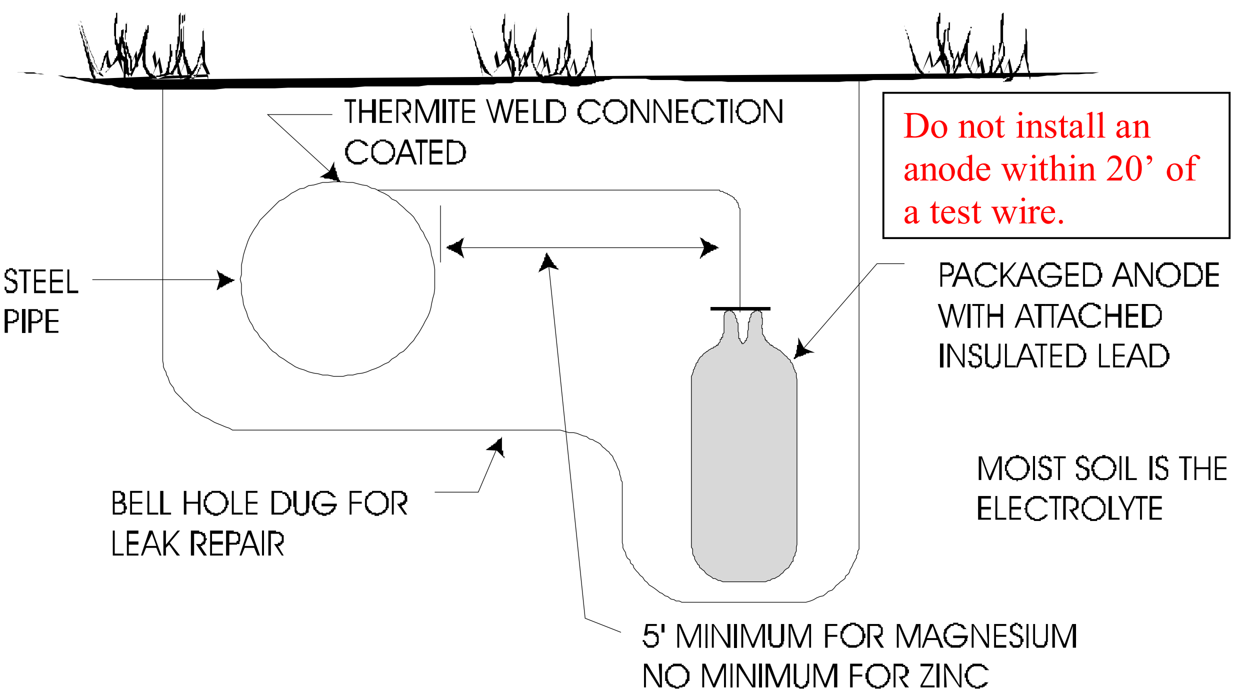
Sacrificial anode systems accomplish protection by coupling a magnesium or zinc anode to the pipeline for current to flow from the anode to pipeline, progressively destroying “sacrificing” the anode and protecting the pipeline. A galvanic or sacrificial anode is able to provide protective current to a steel structure because of its relative position in the galvanic series as compared to steel. Magnesium and zinc anodes are commonly used for low resistivity environments with typical anode sizes of 17 or 34 pounds. The advantages of sacrificial anodes include no external power requirement, low voltage output, no voltage variance, ease of installation, location adaptability, no maintenance, and no inspection requirements. Sacrificial anodes are not applicable to long lengths of new bare steel lines. Similarly, platinum rods are commonly used inside heater treaters, separators, filters, and salt-water disposal tanks. See examples of magnesium anode and installation below.

Rectifier ground bed systems include an AC power supply, a rectifier unit, a ground bed of anodes, connecting cables, and the pipeline: see example below. The rectifier utilizes a transformer to step down high AC line voltage to low AC voltage, then utilizes a rectifying element to converts the low AC voltage to DC which is transferred by a single cable to a high silicon iron or graphite anode ground bed located 150 to 450 feet from the pipeline. Rectifier ground bed system advantages include variable DC voltage application, protection of bare steel lines, and automation for varying moisture conditions. Disadvantages include possible foreign structures interference, unintentional current interruption, required regular maintenance, and higher operating costs. A note of caution: electricians unfamiliar with DC power have a 50-50 chance of hooking up an impressed current system backwards.

Example of typical magnesium anode
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



Example of typical sacrificial magnesium anode connection to pipeline
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



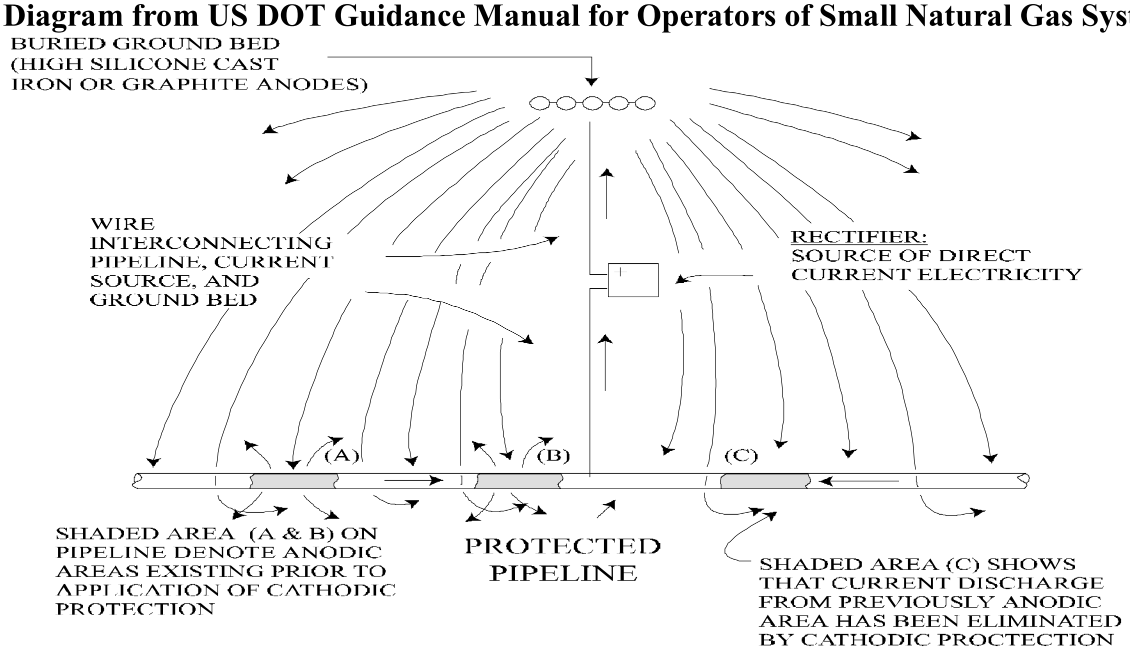
It is usually not economical to protect an entire "bare pipe" pipeline of considerable length. New bare buried pipelines can be assumed to require 1 milliamp per square foot of surface, (~50 amps for 1 mile of 30", ~ 3 amps for 1 mile of 2 3/8"). However, "hot spot" protection, generally economically justified, can be utilized to protect only the very corrosive soil sections. Hot spot protection extends the useful life of the entire pipeline by the application of cp to only the severely corroding areas. Installation of the anodes should be made at a distance of at least 10 ft perpendicular to the pipeline when replacing line sections or applying repair clamps. Most oilfield supply companies carry anodes and Cadweld guns for connecting anodes to the pipeline. See attachment example below.

The industry and governmental standard for cp effectiveness is – a negative (cathodic) potential of at least 850 mV or 0.850 V with cp applied when measured with respect to a saturated copper-copper sulfate reference electrode. This 850 mV measurement consists of the 550 mV natural difference between non-corroding steel and the CSE plus 300 mV caused by the inflow of current. Naturally occurring corrosion cells have voltages less than 300 mV. The – 850 mV is the most widely used, can be taken with current applied, take less time to measure, requires only minimum equipment, personnel, and vehicles, and there is no need to compare to previous readings.

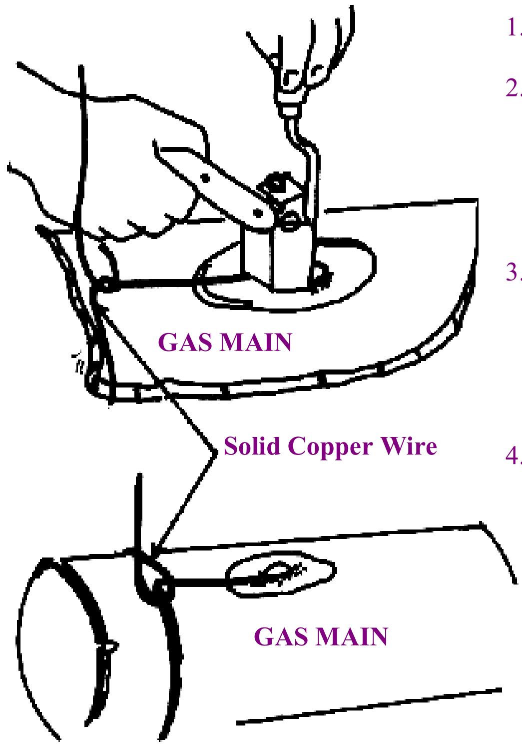
Over time, the corrosion process often results in the formation of insoluble corrosion products that provide a level of protection called passivity. Therefore, the rust buildup often acts as a partial barrier to further corrosion. The study revealed that production storage tanks set in clay do not appear to suffer from the effects of corrosion. Furthermore, metal brine tanks with one or barrels of crude added do not experience the accelerated corrosion experienced by other tanks without crude, due to the coating action provided by the crude.

Cathodic protection requirements are established through soil resistivity measurements taken before and after pipeline and cp system installation. Stripper well operators typically do not utilize soil testing but some other method based on experience or rule of thumb to determine cp requirements.

Example of typical rectifier ground bed system
Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



Example of Procedure for installing a magnesium anode by Thermo-weld Process Diagram from US DOT Guidance Manual for Operators of Small Natural Gas Systems



1. Loop wire as shown to avoid strain on bond.
2. Insert conductor in mold-do not push end of conductor past center of tap hole. Drop metal disc over tap hole. Remove all starting power from cartridge by tapping the inverted cartridge on lip of mold.
3. Close cover, hold mold steady. Ignite starting power with flint gun as shown. When powder fires, remove gun immediately. Hold mold steady for 10 seconds. Remove slag from weld.
4. See the manufacturer's recommendation before proceeding.

After welding, all exposed pipe should be well coated and wrapped.

Pipeline Protective Coatings: Pipelines are corrosion protected through coatings to ensure reliable service over a long time. Coating qualities include effective electrical insulator, effective moisture barrier, applicability, ability to resist holidays, good adhesion to pipe surface, ability to withstand normal handling, storage, and installation, resistance to disbanding, ease of repair, and environmentally nontoxic. Pipelines coatings include coal tar enamels, mill applied tape systems, crosshead extruded polyolefin with asphalt/butyl adhesive, dual side extruded polyolefin with butyl adhesive, fusion bonded, and multi layer epoxy/extruded polyolefin systems. Pipeline coatings are most effective when installed in combination with cp due to the defects associated with all coatings. A cp system will only need to protect the minute areas of steel exposed rather than the whole surface of an uncoated structure.

The current requirements for pipeline corrosion protection are reduced through coatings to 5% to 10% of the cost of protecting bare steel pipe. Therefore, coatings on a cathodically protected pipe reduce the surface area of exposed metal on the pipeline, increase the overall resistance, and thereby reduce the current required for the protection of underground pipelines. The cp current then flows principally to holidays or voids in the coating where a calcareous deposit forms further reducing the current required for cp.

Coatings include both organic and inorganic. Organic coatings include enamels, hot applied mastics, cold liquid coatings, hot applied waxes, cold applied waxes, prefabricated films and tapes, and extruded plastic coatings. Inorganic coatings such as enamel or epoxy paints offer a temporary yet generally sufficient solution to corrosion problems. Metallic coatings, such as nickel plating are generally not appropriate for oilfield application except in rare instances.

Internal coatings are achieved on steel storage tanks by the oil that lines it, while wells that produce oil by pumping are often protected inadvertently though the coating of oil or paraffin generally observed due to stuffing box leaks.

Coatings - Surface Equipment Painting: Coatings for cp for most surface equipment generally includes the application of primer and paint. Stripper oil and gas operators typically utilize various primer and paint systems to combat corrosion on most metal surface equipment surfaces like wellheads, separators, dehy's, and fluid storage tanks. Coatings should be formally inspected annually, while well tenders should casually inspect the facility with every visit. Any coating defects should be addressed as soon as possible to minimize the effects of corrosion or noted for the annual maintenance program. Once a surface facility has been properly coated, repainting should not be necessary for at least five to ten years except in extreme conditions.

Painting is the oldest and most widespread means of combating corrosion, but cannot be considered as a cure-all. Enamel paints should be selected to suit the particular corrosion conditions affecting the structure to be protected. The most important aspects of painting are surface preparation, product selection, and proper mixing.

The first and most important step in painting is surface preparation. Painting industry standards call for solvent cleaning, hand tool cleaning, power tool cleaning, white metal cleaning, commercial blast cleaning, brush off blast cleaning, pickling, near white metal blast, power tool to clean metal, water jet cleaning, or industrial blast. ***However, stripper well operators should ensure that surface are clean, free of oil and grease, all loose mill scale, rust, paint removed by scraper or wire brush, and that the surface is dry.*** High-pressure portable steam cleaners have also been found to be appropriate for use in the field for hard to clean areas.

The second step is product selection. Stripper well operators often use exterior enamel paints supplied by local oilfield equipment suppliers. Typical oilfield paints include Rustoleum, Tnemec Alkalyd Enamel, and Vangaurd Tank and Rig Paint (Miller Supply).

The third step in painting is proper mixing of the paint. The manufacturer's instructions should be carefully followed since inadequately mixed or improperly thinned paint will result in greatly reduced protection. Paints of good quality give satisfactory results because the manufacturer has properly proportioned the pigment and vehicle.

Summer student help is often used by stripper well operators to achieve adequate, affordable, corrosion protection through painting by brush or roller. Two days are generally required to complete painting for most facilities with a two-man crew; day one for surface preparation, day two for paint application. A third day may be required for wells with pumping units or tank batteries with more than two tanks.

Corrosion Resistant Materials: Corrosion resistant materials can be non-metallic or corrosion resistant alloys. Materials utilized for stripper well applications include plastic, stainless steel, and fiberglass, while plastic is the predominant product of choice for both fluid storage tanks and pipeline material.

The primary use of plastic is in pipelines either as original material, complete replacement, or as a liner inside of existing pipelines. General limiting factors in applying plastic are its maximum pressure rating, temperature rating, susceptibility to damage during installation, or damage by offset construction.

Sliplining, or plastic pipe insertion renewal, is a cost effective method of providing mechanical integrity to a gas gathering system affected by corrosion. A brief summary of the Plastics Pipe Institute Pipeline Rehabilitation by Sliplining with Polyethylene Pipe is presented in the Gathering-Production Line Section.

Plastic tanks are utilized for the storage of produced brine, but not recommended for the storage of any produced hydrocarbons. Plastic tanks are often painted to further minimize degradation by ultraviolet rays. Plastic tank guidelines are provided in the Production Tank Section.

Plastic is also utilized for lining tubing or coating packers in corrosive downhole environments or for saltwater disposal applications. Stainless steel needle valves are used extensively throughout the industry for pressure gauges. Fiberglass use has diminished due to the limited number of manufacturers and the superior attributes of plastic.

Dielectric Isolation

Insulating joints are used to break the metallic path, thereby interrupting current flow, and are typically inserted as insulating flanges or unions between protected and unprotected pipelines. This type of corrosion control is utilized to limit cp, reduce the effects of stray currents, and to separate dissimilar metals. Insulating joints are typically a requirement by most gas transmission companies between transmission lines and a stripper well operator's gas gathering system. Above ground facilities may act as cathodic current gathering areas for the outsides of well casings and can be protected utilizing isolation unions.

Chemical Inhibitors

Inhibitors slow or prevent corrosion related chemical reactions and are typically added in small concentration as oxygen scavengers, passivators, and biocides. Inhibitors are generally grouped by mechanism as passivating, vapor phase, cathodic, anodic, film forming, neutralizing, organic, precipitating, volatile, and reactive. Inhibitors can be oil soluble, oil soluble brine dispersible, water-soluble, oxygen scavengers, or surfactant based. Application areas include tubing, gathering systems, water disposal lines, oil or water storage tanks, and gas sweetening or dehydration units. Treatments are by batch every two weeks to three months, or by continuous injection. Chemical treatments are generally applied for internal corrosion control, but can be effective on external corrosion control of wells with H_2S on the 4 ½ x 8 5/8" annulus.[i]

N. Corrosion Economics

Every investment made by stripper well operators should be considered carefully. The cost of applying corrosion mitigation methods to existing facilities should be weighed against the structure replacement cost, risk of spills, product loss, associated fines, safety of personnel, and potential litigation.

O. Corrosion Training

It is recommended that operators provide training in corrosion identification and mitigation. Stripper well operators can develop in-house expertise for their employees through the West Virginia University Appalachian Underground Corrosion Short Course held in May each year at the West Virginia University in Morgantown, West Virginia. Three days of training costs approximately $500 for registration, materials, and room and board. NACE corrosion technician certification can be achieved over a period of three successive years. Additional information on the course can be found at www.aucsc.com. Additional materials are available from www.corrosionsource.com, www.corrosion-doctors.org, or www.hghouston.com/services_5.html.

Section II - Where to begin

Once an operator has a general understanding of corrosion, its effects, and possible mitigation methods, the next question is generally "how do I get started?" Since stripper well operators cannot usually afford to implement an immediate corrosion mitigation program on all production operation areas, it is necessary to establish a review – prioritization procedure. Prioritization considerations include identifying: high value wells or gathering systems, corrosion mitigation methods, corrosion correction methods, associated costs, previous corrosion areas, desired facility life, environmentally sensitive areas, significant potential for harm wells, i.e. H2S wells, and wells located in well-populated areas.

A quick overview of all stripper well common corrosion areas is provided as page 21, see Stripper Well Corrosion Mitigation Summary by Corrosion Area. The second page provides an outline to develop an in-house corrosion mitigation program. The third page is a form to utilize in performing annual field reviews. The remaining pages address each major stripper well corrosion area with the major sections are bolded with associated decision trees, procedures, and forms listed accordingly. An index is provided on page 18 listing the individual sections for ease of use. Each major section summary provides a general discussion, identifies the associated common corrosion areas, corrosion identification methods, corrosion repair or replacement methods, corrosion mitigation methods, decision trees, and procedures.

The appendix provides a dictionary of corrosion related terms, a list of "Recommended Web Sites for Corrosion Information", a list of Links for Vendor Information for Various Corrosion Related Products, Recommended Sources of Information,

The remainder of this procedure guide provides information directly related to the identification and treatment of corrosion in the most common areas of stripper well operations including production casing, tubing, wellheads, separators, production storage tanks, and pipelines. While the overall subject of corrosion is complex, for stripper well operators the process can oftentimes be simplified to the proper application of planning, painting, and plastic.

The development of a corrosion mitigation program will ultimately result in the prioritized repair and maintenance of equipment vital to the continued operation of most stripper wells. Properly maintained equipment results in higher profitability, higher resale value, reduced problem solving time, reduced environmental risks, and reduced safety risks.

A second index is provided for procedure guide ease of use on the following page.

Section II Getting Started Forms

Stripper Well Corrosion Mitigation Summary by Corrosion Area

I. Production Casing

- Cover potentially corrosive zones during primary cementing
- Treat annular areas with chemical H_2S inhibitor where appropriate
- Paint top joint and maintain coating
- Minimize standing water in packing area
- Repair surface leaks according to methodology provided
- Repair downhole leaks according to methodology provided

II. Tubing

- Paint top joint and maintain coating – after each pulling
- Coat bright metal wrench marks with spray paint as temporary coating
- Replace top joints according to methodology provided
- Consider plastic lined tubing or fiberglass for saltwater disposal
- Minimize storing used tubing for extended periods of time
- Store tubing on elevated racks and lubricate threads

III. Wellheads

- Paint and maintain coating
- Eliminate leaks; replace, tighten, or tape threaded connections
- Paint exposed sections of field cut threads –spray paint if necessary
- Minimize soil and fluid accumulation around wellhead
- Work valves and lubricate fittings regularly to ensure continued operation
- Valve wellhead outlets to minimize interior oxygen exposure

IV. Separators, Production Units, Gas Dehydrators, and Meters

- Paint and maintain coating
- Eliminate leaks; replace, tighten, or tape threaded connections
- Keep control covers in place and closed / Maintain controls
- Repair vessel coating scratches promptly with spray paint
- Purge interior with carbon dioxide and seal outlets for long term storage

V. Production Tanks

- Paint and maintain exterior coating - Coat bottom with mastic or coal tar
- Set tanks to minimize scraping bottom coating vs. pushing with dozer
- Set tanks on pea gravel rather than sharp edged limestone
- Eliminate connection leaks - identify leaking tank bottoms through tank gauges
- Put two barrels of crude oil in steel brine storage tanks
- Replace steel brine storage tanks with plastic tanks

VI. Gas Gathering Systems

- Install plastic lines within pressure limitations
- Consider hot spot anodic protection for bare steel corrosive areas
- Slipline with plastic on corroded sections rather than removal and new installation
- Use variance reports and check meters to identify mechanical failures
- Set up main lines for pigging to reduce fluid and deposit build-up
- Get training at Appalachian Underground Corrosion Short Course

Form 1 - Decision Tree For Field Wide Corrosion Mitigation Plan Development

Phase I: Identify the Problem

1. Complete field review with well tender utilizing Form 2
2. Prepare well equipment inventory on spreadsheet
3. Prepare wellbore schematics for problem wells
4. Prepare map identifying wells, gathering system, and pipelines (type, size, and age)
5. Estimate average production per well, mcfdeq
6. Prepare gas sales variance report
7. Prepare leak, repair, or replacement summaries

Phase II: Measure the Problem

1. Sort wells by gathering system then by descending mcfdeq
2. Determine system priority by mcfdeq, variance, and environmental concerns
3. Review maps, schematics, and leak summaries
4. Utilize appropriate equipment decision tree form
5. Estimate costs for maintenance, repair, or replacement
6. Prepare economics by well and gas system

Phase III: Solve the Problem

1. Confirm expense justification by payout or net present value
2. Complete work, sell, or plug and abandon
3. Estimate annual budget for expenditures
4. Prepare repair schedule
5. Prepare maintenance schedule
6. Prepare replacement schedule

Phase IV: Monitor the Changes

1. Prepare monthly gas sales variance reports
2. Conduct weekly well tender meetings
3. Complete annual review of all facilities
4. Complete annual pipeline inspection
5. Document maintenance and repairs
6. Review pipeline repairs to identify trouble areas

Form 2 - Annual Corrosion Field Review Data Collection Sheet

I. General Information

Area of Inspection: Lease________________Pipeline____________Other______________

Inspection Completed by: __________________

Date of Inspection: _____-_____-________

II. Identification and Correction

Area	Extent**	Recommended Correction/Protection Method
Downhole – casing	______	____
Downhole - tubing	______	____
Wellhead - casing	______	____
Side Nipples/Valves	______	____
Top Joint - tubing	______	____
Pipeline	______	____
Valve, Master	______	____
Valve, Needle	______	____
Valve,____________	______	____
Valve,____________	______	____
Tank (210 bbl)	______	____
Tank (100 bbl)	______	____
Tank (50 bbl)	______	____
Fitting	______	____
Fitting	______	____
Fitting	______	____
Production Unit	______	____
Separator	______	____
Riser	______	____
Vent/Marker	______	____
Ladder	______	____
Lubricator, TPL	______	____
Plunger	______	____
Rods/Pump/Tbg	______	____
________________	______	____

****Corrosion Extent – Minimal (Min), Moderate (Mod), Severe (Sev)**

III. Methods of Correction: Clean, Protect, Repair, Replacement

Clean	1. Scrape____	2. Wire Brush____	3. Sand____	4. Sand Blast____	
Protect	1. Paint____	2.Prime____	3. Top Coat____	4. Insulate____	5. Flange____
Repair	1. Clamp____	2. Plug hole____	3. Packer____	4.Tank bottom____	
Replacement	Pipeline	1. Replace section____	2.Slipline____		
	Tank	1. Replace steel tank with used steel or plastic tank_______			

IV.Comment:____

____

____

____

Section III - Production Casing Corrosion Summary

General Discussion: Production casing generally experiences corrosion where exposed to environmental conditions, oxygen, H_2S, CO_2, and moisture. The loss of mechanical integrity in the top of joint of casing, typically near the packing area, causes multiple problems including loss of product and ceased production operations. Potential surface problems are identifiable by well tenders, but downhole problems are often gradual and not observed until mechanical failure occurs. Cased-hole logs can identify general casing conditions and potential trouble areas but are generally cost prohibitive for stripper well operators. Operators are best served by planning sufficient primary cement over potential trouble areas, maintaining chemical inhibitor programs, coating surface equipment, and providing training for well tenders in casing leak identification.

Common Corrosion Areas:
- Exterior at surface - At the surface near the packing area
- Exterior downhole - Just above top of cement
- Exterior downhole - Across from hydrogen sulfide bearing zones
- Exterior downhole - Across from coal bearing intervals

Corrosion Identification Methods:
- Visual surface inspection by well tender
- Loss of annular pressure or influx of additional fluid
- Discolored produced fluid – muddy, unusual odor such as rotten eggs (H_2S)
- Possible increased pressure on secondary string (intermediate or surface casing).
- Cased-hole logging Baker Hughes logging capabilities include
- Vertilog: 360° identification of internal and external corrosion
- Vertiline: Magnetic flux leakage for internal and external inspection of pipelines.
- Digital Magnelog – Identify multiple pipe string wall thickness changes

Corrosion Repair Methods
- Surface leak see Casing Repair Procedure 1
- Set Tubing and packer to isolate leak. See Casing Repair Procedure 2
- Mechanical casing patches – Expensive and results in loss of internal diameter
- Squeeze cementing of affected area - Costly and sometimes unsuccessful

Corrosion Mitigation Methods
- Provide cement sheath around pipe through corrosive interval with primary cementing.
- Chemical inhibition of annular fluids generally by batch treatment
- Casing metallurgy modifications to address H2S
- Cathodic protection: usually effective for wells less than 10,000'; estimated cost $5,000

Decision Trees
- Top Joint Casing Leak
- Downhole Production Casing Leak

Procedures
- Top Joint Casing Repair Procedure
- Downhole Casing Repair Procedure – tubing and packer

Form 3 - Decision Tree For Top Joint Production Casing Leak

Phase I: Identify the Problem (Indications of Failure)

1. Well tender observance of potential mechanical failure due to corrosion
2. Observance of physical sign of failure: gas leaking from casing at packing
3. Loss of pressure on tubing and tubing casing annulus
4. Loss of production; unable to remove fluids

Phase II: Measure the Problem

1. Estimate production loss
2. Review repair history
3. Estimate remaining reserves
4. Estimate cost of repair or replacement: See Casing Repair Procedure 1

Phase III: Solve the Problem

1. Confirm expense justification by payout or net present value
2. Complete work, sell, or plug and abandon
3. Prioritize work based upon economic benefit

Phase IV: Monitor the Changes

1. Monitor post workover production
2. Compare results to predicted production and expenditure
3. Maintain mechanical integrity by periodic painting

Production Casing Surface Corrosion Repair Procedure

- Produce well to line pressure prior to moving in rig, then vent to tank
- Precut and bevel equivalent weight/foot 4 ½" casing (6" to 1'of casing and collar)
- Move in and rig up service unit. Set out appropriate safety equipment
- Conduct safety meeting, identify location hazards, review well information and objectives, modify plan to maximize safety and repair results
- Check pressure on 8 5/8" x 4 ½" annulus, safely vent to atmosphere away from well head
- Remove top ring of wellhead (8 5/8" x 4 ½")
- Trip out of hole with all or part of tubing. May want to check total depth of well
- Make up landing joint (8' to 10') of tubing and compression packer
- Place precut 4 ½" nipple over setting joint of tubing with packer
- Set 4 ½" compression packer at approximately 2' below top of 8 5/8" x 4 ½" ring
- Load annulus above packer between tubing and 4 ½" casing to ensure packer setting
- Vent 4 ½" casing gas below packer through tubing to atmosphere to production tank
- Remove top split ring, rubber packing, and bottom split ring in 8 5/8" x 4 ½" head
- Reinstall rubber packing and put small amount of water on top to ensure good seal
- Mark 4 ½" casing to cut below corroded area
- Use cutting torch to cut, split, and removal damaged area - be prepared for possible fire
- Prepare new cut for welding by first grinding then beveling
- Weld precut 4 ½" nipple with collar to prepared cut
- Modify split rings as necessary to reinsert around 4 ½" casing due to additional weld
- Reinsert bottom split ring, packing rubber, and top ring
- Put on top ring and tighten
- Release and pull packer
- Trip in hole with tubing to appropriate depth*
- Swab as necessary to kick off well. Return well to production and maintain

Estimated costs to repair corrosion-impacted wellhead

Service rig and crew	__ hours @ __ per hour	$________
Dozer	__ hours @ __ per hour	$________
Packer (Baker R4)		$________
Supervision		$________
Reclamation		$________
Total		$

**May want to consider checking TD, sand pumping, and swabbing while rig is on location

Form 4 - Decision Tree For Corrosion Mitigation – Downhole Production Casing

Phase I: Identify the Problem (Indicators of Mechanical Failure)
1. Decreased gas production by chart observation or integration volumes
2. Well loaded up with fluid: verify with echometer
3. Overall increased produced fluids: tank measurement
4. Increased pumping time required to maintain production
5. Hydrogen sulfide odor: Check concentration with caution
6. Discolored produced fluids
7. Pressure loss on tubing and/or tubing-casing annulus
8. Change in chemical analysis of produced fluids

Phase II: Measure the Problem
1. Compare well condition to previous or offset well experience
2. Estimate top of cement
3. Confirm or determine appropriate fluid removal method*
4. Estimate cost of tubing-packer installation for remedial action
5. Estimate remaining reserves / production potential by pressure and decline curve analysis

Phase III: Solve the Problem
1. Confirm expense justification by payout or net present value
2. Complete work, sell, or plug and abandon
3. See downhole casing repair procedure
4. Prioritize work based upon economic benefit

Phase IV: Monitor the Changes
1. Monitor post workover production
2. Compare results to predicted
3. Continue corrosion inhibitor program in casing and casing-tubing annulus fluids

*Installation of packer and tubing may necessitate change of production method, installation of a second string of tubing, or pumping unit and slim hole rods.

Downhole Casing Repair Procedure: Utilizing tubing and packer to isolate hole in casing

- Produce well to line pressure prior to moving in rig, then vent to tank
- Move in and rig up service unit and required equipment
- Conduct safety meeting, identify location hazards, review well information and objectives, modify plan to maximize safety and repair results
- Check pressure on casing tubing annulus, then vent to tank
- Trip out of hole with tubing and check total depth of well
- Trip in hole with seating nipple and tubing
- Set packer approximately 100' above estimated top of cement with sufficient tail joint(s) according to preferred placement to perforated interval(s)
- Swab to ensure proper packer placement (check annular pressures)
- Run additional tubing and rods if necessary
- Swab as necessary to kick off well
- Return well to production and maintain

Form to estimated cost to repair corrosion-impacted wellhead

Service rig and crew	__ hours @ $__ per hour	$ ______
Dozer	__ hours @ $__ per hour	$ ______
Packer		$ ______
Supervision		$ ______
Reclamation		$ ______
Tubing (second string for optimized tbg plunger)		$ ______
Rods		$ ______
Pump		$ ______
Pumping Unit		$ ______
Roustabout	__ hours @ $__ per hour	$ ______
Total		**$ ________**

Section IV - Tubing Corrosion Summary

General Discussion

Tubing corrosion is often found at the exterior of the top joint in the packing area, on the interior and exterior of used tubing left on the surface for extended periods of time, and downhole in corrosive environments associated with enhanced oil recovery or H_2S. Stripper wells operators often utilize used strings of tubing and rods due to the economic benefits of used equipment.

Common Corrosion Areas

- Exterior at the surface in the packing area
- Interior in the string in salt water disposal wells or enhanced recovery wells
- Interior in pumping wells where rods wear the same tubing areas continuously

Corrosion Identification Methods

- Well tender observance of potential mechanical failure due to corrosion
- Decrease in overall production (oil, gas, and water)
- Decrease in casing pressure
- During regular servicing
- Pressure test with tubing plunger set in seating nipple (wet string)

Corrosion Repair or Replacement Methods

- General treatment is to replace affected joint(s) upon visual inspection

Corrosion Mitigation Methods

- Chemical Inhibition by batch, plastic tube, or continuous injection with pump
- Plastic lined tubing
- Fiberglass tubing
- Minimize used tubing storage time on racks due to exposure to oxygen
- Store tubing on racks as well for extended storage and grease threads

Decision Trees

- Top Joint Tubing Leak

Procedures

- Not applicable

Form 5 - Decision Tree For Top Joint Tubing Leak

Phase I: Identify the Problem (Indications of Failure)

1. Well tender observance of potential mechanical failure due to corrosion
2. Observance of physical sign of failure
3. Loss of pressure
4. Loss of production

Phase II: Measure the Problem

1. Estimate production loss
2. Review repair history
3. Review wellbore schematic
4. Review remaining reserves
5. Estimate cost of repair or replacement

Phase III: Solve the Problem

1. Confirm expense justification by payout or net present value
2. Complete work, sell, or plug and abandon
3. Prioritize work based upon economic benefit

Phase IV: Monitor the Changes

1. Monitor post workover production
2. Compare results to predicted production and expenditure
3. Continue maintenance program of periodic painting to minimize future failures

Section V – Wellhead Corrosion Summary

General Discussion

Wellheads suffer from corrosion due to harsh operating environments experienced during drilling, completion, and operations. Wellheads should be cleaned and painted after surface facility installation is complete. Soil should be cleared from the wellhead to elevation grade minimizing fluid accumulation, exposing all valves or outlets. Outlets should be equipped with valves to minimize oxygen exposure. Only the surface exposed portions of the tubing and casing strings generally require maintenance due the diminished pressure requirements over time. Even small connection leaks are detrimental and should be repaired quickly. Field cut threads and wrench marks will become anodic and therefore should be painted. Valves should be operated regularly to ensure continued ease of operation.

Common Corrosion Areas

- Un-cemented intervals bearing H_2S
- Un-cemented coal bearing intervals
- Packing area - top joint tubing or casing corrosion
- Outlet threads without valves

Corrosion Identification Methods

- Visual weekly inspection by well tender
- Annual formal inspection of facility
- Loss of wellhead pressure
- Visual of gas leaking at surface
- Loss of overall production
- Increase in fluid production
- Unusual odor at wellhead – H_2S Leak

Corrosion Repair Methods

- **See production casing surface repair procedure**

Corrosion Mitigation Methods

- Paint after removing all loose paint, oil, and grease.
- Remove soil from around the wellhead down to surface casing – provide proper drainage
- Put plugs and valves in all open threads with proper lubrication
- Operate all valves on a regular basis
- Lubricate fittings on a regular basis
- Tighten leaking fittings
- Use dielectric insulation flanges

Decision Trees

- Not Applicable

Procedures

- See top joint tubing and casing repair procedures

Section VI - Separators, Production Units, Gas Dehydrators, and Meters:

General Discussion

While interior corrosion is difficult to identify, exterior corrosion troubles generally occur where connections leak over time or around heater tubes. Production unit controls should be kept covered for maximum life. Covers or sealing gasket replacement should be considered for gas orifice and positive displacement meters.

Common Corrosion Sources

- Vessel exteriors
- Interior
- Leaking connections
- Fire tube area

Corrosion Identification Methods

- Visual inspection of exterior corrosion
- Interior corrosion difficult to identify, possibly caused by H2S, or Carbon Dioxide
- Weekly well tender visual inspection
- Annual formal facility inspection

Corrosion Repair Methods

- Replace frozen valves
- Operator will need to decide when to field repair or shop repair extensive corrosion

Corrosion Mitigation Methods

- Primer and paint on shop coat initially, then maintain coating
- Promptly paint all scratches (spray paint ok)
- Maintain production unit control covers
- Employ sealing compound on all connections and make up tight
- Plug outlets and purge vessels pulled from service with nitrogen or carbon dioxide
- Review anode status of production units so equipped

Decision Trees

- Not Applicable

Procedures

- Not Applicable

Section VII - Production Tank Corrosion

General Discussion

Production storage tanks are generally constructed of steel, plastic, or fiberglass. Steel tanks provide excellent storage for crude oil and brine especially when combined with a well-maintained exterior coating. Leaking tanks cause multiple problems including ceased production, loss of product, use of resources, and associated environmental penalties. Plastic and fiberglass tanks degrade and become fragile with time, while buried cement vaults can crack and leak.

Common Corrosion Areas

- Exterior bottom of tank – environmental conditions and coating
- Interior of the top load line – water and oxygen
- Interior of steel brine storage tanks due to oxygen aggravated by chlorides
- Exterior heater tube areas
- Exterior near saltwater leaks, drains and general exterior
- Exterior where operator identification or product warning labels have parted from tank
- Exterior tank tops from splash due to separator or well unloading

Corrosion Identification Methods

- Visual through oil, water or excessive corrosion
- Tank gauges variances identified by well tender
- Production report variances identified by production manager
- Determine soil resistivity
- Complete annual inspections of facilities

Corrosion Repair Methods

- Remove from service and transfer to storage yard where multiple tanks can be repaired
- Purge tank with nitrogen or carbon dioxide prior to cutting or welding
- Seal tank heater tubes by welding shut, when they begin leaking
- Suitable fire and safety equipment at the location
- Repair tanks by welding on patch, or replacing entire bottom of tank

Corrosion Mitigation Methods

- Paint with top coat and maintain coating:
- Coat bottom and 1 foot of the sides with coal tar epoxy (mastic) prior to putting in service
- Use pea gravel or sand rather than sharp edged limestone for base material
- Set tanks slightly above grade in dike without dozer to avoid damaging coating
- Limit standing water in dikes and eliminate brine discharge on dike interior
- Put 1 to 2 barrels of crude oil in steel tanks for brine only wells
- Eliminate vegetation (moisture) from around bottom edge of tank
- Utilize plastic tanks for brine storage
- Consider Cadwelding (4) 17# magnesium anodes at NESW positions

Decision Trees

- See Production Storage Tank Decision Tree

Procedures

- See Production Storage Tank and Plastic Tank Considerations

Form 6 - Decision Tree For Corrosion Mitigation – Production Storage Tanks

Phase I: Identify the Problem (Indicators of Mechanical Failure)
1. Significant exterior corrosion
2. Brine or crude oil at the exterior of the tank
3. Decreasing tank volume based on tank gages
4. Static tank volume with normal gas production

Phase II: Measure the Problem
1. Estimate product loss
2. Review repair history
3. Estimate associated remaining reserves
4. Estimate cost of repair or replacement: See Tank Repair and Replacement Options*

Phase III: Solve the Problem
1. Confirm expense justification by payout or net present value
2. Complete work, sell, or plug and abandon:
3. Prioritize work based upon economic benefit

Phase IV: Monitor the Changes
1. Monitor post remediation production
2. Compare results to predicted production and expenditure
3. Eliminate any connection leaks
4. Maintain mechanical integrity by periodic painting (enamel or epoxy based paints)
5. Complete annual inspection of surface facilities

***Tank Repair or Replacement Options**
1. Repair tank on location
2. Remove tank and repair off site, return to service
3. Replace steel tank with (smaller) plastic tank
4. Remove and do not replace, if no longer necessary

Production Storage Tank Considerations
Plastic
1. Size tank appropriate to production
2. Tanks can be set on clay, sand, or gravel
3. Utilize manufacturers suggested method for hook up
4. Paint tank to minimize Ultra Violet degradation
5. Utilize tanks for brine storage only as recommended
6. Mechanical integrity may diminish through aggressive direct blow downs to tank.

Steel
1. Size tank appropriate to production
2. Coat bottom of tank and 1’ of sides with coal tar or mastic
3. Paint remaining surface with top coat after setting tank ASAP
4. Add 1 to 2 barrels of crude oil to insulate interior of tank of brine only wells
5. Tank labels encourage corrosion once the top has become dis-bonded allowing moisture to collect. Replace as necessary, especially when repainting.

(Steel Tank Dimensions) 100 barrels - 8’6” diameter x 10’, 210 barrels– 10’ diameter x 15’

Plastic Tank Summary

Norwesco, Snyder, and Poly Processing Company manufacture oilfield brine storage tanks. Plastic tanks should be painted to reduce Ultra Violet (UV) ray degradation. Crude oil should not be stored in plastic tanks since it will degrade and soften the tank. The limited warranted is three-year service life while many tanks under normal use exhibit ten to fifteen year lives. The maximum continuous temperature is 100° F and the maximum pressure is atmospheric. Most tanks are translucent although they are available in solid green or black. All tanks are of one-piece construction from linear or cross-linked High Density Polyethylene (HDPE) plastic.

Safety Checklist (after Poly Processing Company)

- Confirm storage product compatibility with type of PE tank and fittings
- Maintain atmospheric pressure through adequate tank ventilation
- Protect tank from over pressurization by tanker trucks and fill line purging
- Prevent excessive heat near or inside tank. Maximum continuous temp 100° F
- Have and use Material Safety Data Sheets (MSDS) for product being stored
- Regard tanks as confined spaces and follow proper entry procedures
- Secure ladders properly at top and bottom with only one person on a ladder at a time
- Avoid standing on the slippery and flexible tank domes (no weight load rating)
- Never move tanks while holding liquid
- Never allow personnel under tank when it is being lifted

Installation Checklist (after Poly Processing Company)

- Remove and check the uninstalled parts typically shipped inside the tank
- Locate the tank wisely to facilitate servicing and minimize expenditures
- Protect personnel from chemical danger in the event of a leak
- Protect the tank from traffic damage and excessive heat (100° F maximum)
- Tanks are designed for aboveground use only
- Use adequate secondary containment according to governmental requirements.
- Use Teflon tape, paste, or both at all threaded connections. Do not over tighten.
- Use flexible, hose type connections to preserve warranty. Flexible hoses allow for tank expansion and contraction, and reduce pump and piping vibration stress on the tank.
- Support hoses, piping, and valves using structural support independent of the tank sidewall and dome.
- Fully support the entire bottom of the tank on a clean smooth concrete foundation or in a PPC approved metalwork. Failure to provide proper foundation and support constitutes a misuse of the tank and will void your warranty.
- Fill the usable capacity of the tank with water and hydro test for 24 hours after installation, prior to product being introduced to ensure tank and fitting integrity.
- Install appropriate and required warning labels.
- Tanks should be inspected on a routine scheduled basis and findings reported

Section VIII - Natural Gas Gathering Lines and Oil Production Lines

General discussion

Corrosion in natural gas gathering lines and production lines results in the loss of saleable product, spill cleanup time, environmental liabilities, and the cost of repair or replacement. Unfortunately, many stripper well lines are not coated or cathodically protected, and gathering system information is not well documented. Gathering system components and modifications should be documented and mapped.

Common Corrosion Areas:

- Externally, where pipelines exit or enter the ground
- External where soil types or conditions are conducive to corrosion
- Internally, where fluid remains stagnant, for example, in low-lying areas.

Corrosion Identification Methods:

- Well tenders, landowners, and domestic gas users.
- Production variance reports (Comparison of master meter to total of individual meters)
- Use of line pressure monitoring and check meters
- Physical signs: odor, hissing, bubbling, dead vegetation, fire, and moist field dry spots
- Oil spills are generally identified as seepages or as rainbow sheens
- Use of gas detectors and scheduled pipeline inspections
- Installing pipe to soil potential test stations even if no cp is installed
- Utilize corrosion coupons from chemical companies for internal corrosion
- Close interval resistivity surveys for trouble areas
- Document historic pipeline problems

Corrosion Repair Methods

- Clamps: Inexpensive but possible additional damage due to oxygenated soil
- Section replacement for bare steel: beware galvanic corrosion due to new pipe-old pipe
- Plastic replacement: inexpensive, low-pressure limitation
- Sliplining existing steel lines with plastic
- Fiberglass: Expensive
- Fiberspar: Glass fiber reinforced epoxy laminated pipe rated for 200 to 750 psi, can be spooled up to four miles; typically not for stripper well operators

Corrosion Mitigation Methods

- Map the system
- Document all repairs and replacements
- Hot spot protection for old bare steel lines in aggressive soil conditions

Decision Trees

- Pipeline or Production Line Leak Decision Tree

Procedures

- Gas Gathering System Identification and Review Steps
- Sliplining Procedure
- Plastic Pipe Pressure Rating Guide

Gas Gathering System Identification and Review Steps

- Identify entire system of wells and pipeline on section township map
- Identify the following
  - Size and lengths
  - Construction material(s) (plastic, steel, coated, protected)
  - Installation dates
  - Cathodic Protection or coatings
  - Valves
  - Meters
  - Compressors
  - Drips
  - Domestic Gas Users
- Document work or replacement history
- Prepare topographic and line drawing – very important!
- Collaborate with superintendents, well tenders, roustabouts, and installers
- Field review system starting with most important systems first, greatest mcfd
- Walk system sections with global positioning system, (Garmin GPS 12), line locator, flagging tape, and leak detector: noting all gps readings in notebook.
- Utilize gps to identify valves, road crossings, leaks, and potential trouble areas
- Download GPS data to Terrain Navigator software or equivalent
- Update maps based upon field review
- Field review annually and update maps
- Continue to document all pipeline work

Instrumentation

- Gas sniffers
- Global Positioning Systems (GPS)
- Two terminal resistivity determination
- Four terminal resistivity determination, Wenner method
- AC Soil rod, typically copper sulfate
- Pipeline locator

Brief History of High Density Polyethylene Pipe:

High-density polyethylene pipe, or HDPE, has become a significant part of the in the fight against corrosion. According to the American Gas Association, in 1965 there was only 9,200 miles of plastic pipe being used, 10% of the total pipe utilized for pipelines, while five years later the number grew to 45,800 miles. By 1982, there was 215,000 miles, with greater than 500,000 miles in 1996, over 90% of the total pipe utilized for pipelines. According to the Plastic Pipe Institute (PPI), HDPE has lower life cycle costs including corrosion resistance, leak tight, lower instances of repair, and maintains optimum flow rates.

Personnel and contractors who install or repair, HDPE, should be familiar with the proper methods for installation and fusing. Black HDPE pipe contain at least 2% carbon black and will resist damage from sunlight. Other colored products are compounded with antioxidants, thermal stabilizers, and UV stabilizers, but these UV stabilizers will eventually deplete, therefore, non-black should not remain in unprotected outdoor service for more than 2 years. Plastic pipe has limitations but many can be overcome with proper markers (surface and underground), proper application, and pressure relief valves.

Form 7 - Decision Tree Form for Pipeline or Production Line Leak

Predicting pipeline failure is difficult for most stripper well operators since most methods of evaluating pipeline integrity are cost prohibitive. Operators should utilize detailed map preparation, scheduled line monitoring, production variance reports, and installing plastic lines whenever possible. The pressure limitations associated with plastic are generally sufficient for most low-pressure stripper well repairs or replacement. Plastic pipe is appropriate for new well installation with proper pressure control or pressure relief devices.

Phase I: Identify the Problem (Indicators of Mechanical Failure)

1. Decrease in fluid production (production line leak). Tank gauge.
2. Decrease in gas production: chart review
3. Decrease in line pressure
4. Significant variance of individual meter(s) to master meter (>5%)
5. Observance of physical sign (see Physical Signs of Gas Leak)
6. Review map, known, and documented histories of previous pipeline trouble areas
7. Utilize gas detection equipment

Phase II: Measure the Problem

1. Estimate production loss
2. Review pipeline repair history
3. Review map of gathering system
4. Review options for repair*
5. Estimate cost of repair or replacement

Phase III: Solve the Problem

1. Confirm expense justification by payout or net present value
2. Complete work, sell, or plug and abandon
3. Prioritize work based upon economic benefit

Phase IV: Monitor the Changes

1. Monitor post workover production
2. Compare results to predicted
3. Note pipeline changes to map
4. Analyze pipeline systems for upgrade potential to minimize future failures

***Pipeline Repair Options**

- Clamp
- Small section replacement with plastic
- Small section replacement with steel (coated on uncoated)**
- Large section replacement with plastic
- Slip lining existing steel line with reduced id plastic (See slip lining procedure)

**Consider using anodes for hot spot protection on leak areas
**Consider installation of pipe to soil test stations when repairing existing steel pipelines

Pipeline Rehabilitation by Sliplining with Polyethylene Pipe
(after Killebrew, Inc. and Institute Forms Technologies)

Sliplining is an economical method of restoring structural integrity to corroded pipes, and is suitable for water mains, sewers, gas mains, industrial plants, and storm water lines. Sliplining involves installing a new, factory-manufactured pipe inside an existing deteriorated pipe. With sliplining, it is possible to repair long lengths of pipe and negotiate slow bends with this process. High-density polyethylene thermoplastic pipe (HDPE) is commonly used for pipes up to 48 inch in diameter and fiberglass reinforced polyester pipe (FRP) for larger pipes. Sliplining requires the old pipe to be in sufficient condition to withstand having a new pipe inserted without collapsing or moving. The gas industry has been inserting polyethylene (PE) pipe into deteriorating gas mains for many years.

During sliplining installation, excavations are made for an insertion pit and at each lateral or tie in location. The liner, usually fused lengths of P.E. pipe creating one continuous pipe, are then pushed into an existing larger pipe, or a winch cable can be inserted through the existing line and then pull the line through.

Sliplining advantages include:

- Ability to rehabilitate structurally unsound pipe
- Efficient alternative to removal and replacement, and minimizes surface disturbance
- Five hundred foot insertions are not uncommon
- Diameter reduction generally made up by improved flow of continuous plastic line

Sliplining disadvantages include:

- Reduced cross-sectional area
- Difficulty locating new leaks because the gas will not surface near the actual leak.

Design considerations include:

- Select the largest feasible diameter, normally 10% less than original internal diameter
- Determining a liner wall thickness
- Analyzing the flow capacity

Sliplining project steps include:

- Isolate and blow down the existing line
- Excavate and cut out sections at both ends of the pipe section and at any tie-ins
- Attach a tapered nosepiece to the front of the PE pipe to push or pull the pipe
- Insert the PE pipe into the existing pipe and begin pulling (or pushing)
- Proceed carefully due to unexpected bends, valves, or diameter changes.
- Provide insertion point protection to avoid damage as new pipe slides into existing pipe.
- Inspect first section for damage as liner pipe is through to the exit excavation.
- Make connection to existing system, purge system, pressure test, return to production

Most oilfield contractors are familiar with sliplining and should be able to assist stripper well operators with designing a replacement procedure. Pipeline construction companies are also familiar with slipline process but may be cost prohibitive for stripper well operators to use.

Plastic Pipe Pressure Rating Guidelines

This form was adapted from API Specifications LE and has been limited to those pipe sizes and SDR ratings that are generally appropriate for stripper well operators. The original chart is for sizes 1.25 inches through 54 inches and 255 psi, SDR 7.3, through 40 psi, SDR 41.0. Refer to supplier's guidelines for updated pressure ratings. The chart reflects the maximum allowable operating pressure in psig at 73.4 degrees F. Federal regulations limit the maximum allowable pressure for plastic pipe to 100 psig for natural gas.

Pressure design calculations are based on the following formula that relates the stress on the pipe wall to internal pressure. P = (2xS/(SDR-1)) x DF x F, where S equals the long term hydrostatic strength in psig, P equals the internal pressure in psig, SDR equals the standard dimensional ratio of D/t, D equals the outside diameter, t equals the minimum wall thickness, DF equals the design factor, and F equals the service factor.

Mueller's Formula For Gas Flow has been found to best describe smooth wall pipe flow like PolyPipe $Q = ((2826/G^{0.425}) \times (P_1^2-P_2^2/L)^{0.575} \times d^{2.725}$, where Q equals the gas flow rate in scf per hour, G equals the gas specific gravity, P_1 equals the pipe inlet pressure in psia, P_2 equals the pipe outlet pressure in psia, L equals the length of pipe in feet, and d equals the pipe internal diameter.

Plastic pipe experiences thermal expansion at a approximately 1 inch per 100 feet of pipe per 10° F change. Coiled lengths are available for ½" through 4", while straight lengths are available for ½" through 54".

PE 3408 Industrial Piping System: Pipe Data and Pressure Ratings for Natural Gas										
Pressure Rating		**SDR 7.3- Max 100 psi**			**SDR 9.0– Max 100 psi**			**SDR 11.0- Max 100 psi**		
Pipe Size	**Nominal OD**	**Wall, In.**	**Avg. Id**	**lbs/ foot**	**Wall, In.**	**Avg. Id**	**lbs/ foot**	**Wall, In.**	**Avg. Id**	**lbs/ foot**
0.500	0.840	0.115	-	-	0.093	-	-	0.076	-	-
0.750	1.050	0.114	-	-	0.117	-	-	0.095	-	-
1.000	1.315	0.180	-	-	0.146	-	-	0.119	-	
1.250	1.660	0.227	1.179	0.44	0.184	1.270	0.37	0.151	1.340	0.31
1.500	1.900	0.260	1.349	0.58	0.211	1.453	0.49	0.173	1.533	0.41
2.000	2.375	0.325	1.686	0.91	0.264	1.815	0.76	0.216	1.917	0.64
3.000	3.500	0.479	2.458	1.98	0.389	2.675	1.65	0.318	2.826	1.39
4.000	4.500	0.616	3.194	3.27	0.500	3.440	2.74	0.409	3.633	2.30
5.375	5.375	0.736	3.815	4.66	0.597	4.109	3.90	0.489	4.338	3.27
5.000	5.563	0.762	3.948	5.00	0.618	4.253	4.18	0.506	4.490	3.50
6.000	6.625	0.908	4.700	7.09	0.736	5.065	5.93	0.602	5.349	4.97
7.125	7.125	0.976	5.056	8.20	0.792	5.446	6.87	0.648	5.751	5.75
8.000	8.635	1.182	6.119	12.01	0.958	6.594	10.05	0.784	6.693	8.42
10.00	10.750	1.473	7.627	18.66	1.194	8.219	15.62	0.977	8.679	13.09
12.00	12.750	1.747	9.046	26.25	1.417	9.746	21.97	1.159	10.293	18.42

Form 8 - Pipeline Inspection or Leak Report
(After Oil and Gas Journal Corrosion and It's Control and USDOT Guidance Manual)

1,) Date: __________________ **2.) Reported by:______________________**
3.) Time: ___________AM/ PM **4.) Phone :(_______) - _______ - _______**

5.) Description of Leak: ____
6.) Gas System Name: ____
7.) Nearest Well or Tank: ____

8.) County: __________________Township: _________________ Section: _______________

9.) Directions from Nearest Intersection: ____
____

10.) Cause of Leak: ____
11.) Condition of Right of Way: Good / Fair / Poor
12.) Length of Line Exposed: __________ Feet **13.)** Pipeline Size: ____________ Inches
14.) Type: Steel/Plastic/Fiberglass **15.)** Pipeline Depth: __________ Feet
16.) Estimated Age of Line: _______Years **17.)** Normal Operating Pressure: ___ Psig
18.) Cathodic Protection/Coating_______

19.) Type of joints: Welded_______ Screwed__________ Other____________

20.) Type of Soil at Surface: Clay / Sandy / Loam (Black Dirt) / Cinders / Refuse

21.) Type of Soil at Pipeline Depth: Clay / Sandy / Black Dirt / Other

22.) Moisture Content: Dry / Damp / Wet

23.) Soil Packing: Loose / Medium / Hard

24.) Describe Pipeline Damage: ____
____
____

25.) External condition: Smooth________ Pitted___________ Depth of Pits__________

Corrective Action Taken:
26.) Pipeline Repair Made: Clamp / Joint Replacement / Section Replacement (____ Feet) /

27.) Line Replacement / Slipline with ______Inch Plastic/ Other_______________________

28.) Installation of Hot Spot Anodes? Yes / No / _____________________________________

29.) Comments:
____
____
____

Estimating Anode Requirements for Bare pipe or Hot Spot Protection

The basic principal of protecting hot spot areas is to apply protection where leaks are occurring. The time to install cathodic protection is at time of leak repair when the line is exposed, the labor is there, the equipment is there, and the cost for an anode and anode installation minimal. The application of anodes will generally be beneficial even without an associated soil resistivity or potential, with 17 # magnesium anodes generally appropriate. (From Pipeline Rules of Thumb Handbook). Operators who complete soil resistivity surveys may consider utilizing a hot-spot criteria of potentials more negative than –600 millivolts or soil resistivities less than 10,000 ohms.

A. Bare Pipe Protection Determination

Step 1 Determine Area of Pipe to be Protected

Calculation: Outside Diameter in Inches x Pi (3.1415) / 12 inches per foot

Example 1: Surface area of 2,000 ft of 4” ((4” x 3.14) / 12) x 2000’ = 2,093 sq ft

Example 2: Surface area of 2,000 ft of 2 3/8” ((2 3/8” x 3.14) / 12) x 2000 = 1,242 sq ft

Step 2 Determine Current Requirements - 1 milliamp per square foot – bare pipe

Example 1: 2,000 ft of 4” - 2,093 sq ft x 1 ma per sq ft = <u>2,093 milliamps</u>

Example 2: 2,000 ft of 2 3/8” - 1242 sq ft x 1 ma per sq ft = <u>1,242 milliamps</u>

Step 3 Determine Number of 17 lb. anodes required at assumed 100 milliamps per anode*

Example 1: 2,000 ft of 4” - 2,093 milliamps / 100 milliamps per anode = <u>20.9 anodes</u>

Example 2: 2,000 ft of 2 3/8” – 1,242 milliamps / 100 milliamps per anode = <u>12.4 **anodes**</u>

Step 4 Determine Anode Spacing

Example 1: 2,000 ft of 4” - 2,000 ft / 20.9 anodes = <u>96 ft</u>

Example 2: 2,000 ft of 2 3/8” - 2,000 ft / 12.4 anodes = <u>161 ft</u>

B. Hot spot protection:

To protect 100’ 4” line hot spot with a 100 milliamp output from 17 lb magnesium anode:

Area of each hot spot: ((4” line x 3.14) / 12) x 100 feet = 105 square feet

No. Anodes: 105 square feet x 1 ma per square feet / 100 ma per anode = 1.05 anodes

For 100’ of 2 3/8” line:

Area of each hot spot: ((2 3/8” x 3.14) / 12) x 100 feet = 62.1 square feet

No. Anodes: 62.1 square feet x 1 ma per square feet / 100 ma per anode = 1.00 anodes

A 17# anode will provide varying levels of protection depending on line condition and soil resistivity. The incremental cost for a 34 lb magnesium may be justified for some operators.

*For single anodes against fully protected pipe (not fully protected, higher current output)

C. Magnesium Anode Output Determination: (Remember that 3,000 ohm soil is a corrosive environment, therefore 1000 ohm soil is very corrosive.)

17 lb anode: 180,000 / soil resistivity: Example for 3,000 ohm soil; 180,000 / 3,000 = 60 milliamps (ma) current output from 17 lb. anode (4000 ohm = 45 ma, 2000 ohm = 90 ma, 1000 ohm = 180 ma)

34 lb anode: 195,000 / soil resistivity: Example for 3,000 ohm soil; 195,000 / 3,000 = 65 milliamps (ma) current output from 17 lb. anode (4000 ohm = 49 ma, 2000 ohm = 98 ma, 1000 ohm = 195 ma)

Pipeline Coating Repair Procedures: (After North Coast Energy)

- Repairing a nick or gouge in the coating
- Repairing a previously coated pipeline after a new weld
- Repairing coating after fittings.

Procedure 1: Repairing a Nick or Gouge in the Pipeline Coating Using Tape

- Clean pipe around the length of the damage and two to three inches on either side
- Remove all jagged edges and any distorted or potential disbonded areas
- Coat pipeline circumference with primer being careful to fill any voids, especially at the edges of the coating
- Start taping at one end, overlapping ½ of the width of the tape each wrap, while keeping constant tension (almost stretching) on the tape
- When finished wrapping, smooth down edges by hand to assure a good bond to the pipe
- Ensure that tape and primer are compatible. There are many tape manufacturers with various widths and thickness available. Not all primers and tape are compatible. Some thicker tapes for areas of stray current or have a plastic backing that has to be removed prior to application.

Procedure 2: Repairing a Previously Coated Pipeline After a New Weld Using Tape

- Wait for the weld to cool, then clean scale off the weld
- Trim the old coating back to good smooth coating and then clean pipe of any dirt or debris back to the clean coating
- Apply primer to all new and cleaned areas to be coated, or over 3” of previously taped, good coating
- Start taping over the previously taped, primered area, overlapping ½ of the width of the tape with each wrap, while keeping tension (almost stretching) on the tape
- When finished wrapping, smooth down edges by hand to assure a good bond to the pipe

Procedure 3: Repairing Coating After the Installation of Fittings Using Tape

- Trim all the old coating back to good smooth coating, and then clean the pipe of any dirt or debris back to the clean coating
- Apply primer to all new and cleaned areas to be coated. In addition, apply primer over 3” of previously taped, good coating
- Plan the application of the tape to avoid wrinkles. It is necessary to have the tape smooth on all surfaces for maximum effectiveness.

Section IX - Appendix

Abbreviations

CP	Cathodic Protection
EMF	Electromotive Force
AST	Aboveground Storage Tank
UST	Underground Storage Tank
MIC	Microbiologically Induced Corrosion
CRA	Corrosion Resistant Alloy
ma	milliamps
ohm-cm	ohm-centimeters

Definitions

Active or Active Metal - A state in which a metal tends to corrode(opposite of passive or noble).
Alkaline - pH greater than 7
Alkyd – Type of resin formed by polyhydric alcohols and polybasic acids
Alloy – Combination of any two elements when at least one is a metal
Ammeter - An electronic instrument for measuring the magnitude of electric current flow.
Anaerobic – Absence of air or un-reacted or free oxygen.
Anode – Positively charged electrode of electrolytic cell where oxidation (corrosion) is the principle reaction.
Atmospheric corrosion - Gradual degradation of a material by contact with substances present in the atmosphere, such as oxygen, carbon dioxide, water vapor, sulfur, and chlorine compounds.
Backfill - Material placed in a drilled hole to fill space around anodes, vent pipe, and buried components of a cp system.
Bare lines – Unprotected steel lines with no coating, sacrificial anodes, or impressed current.
Base - A chemical substance that yields hydroxyl ions (OH-) when dissolved in water.
Bimetallic or Galvanic Corrosion - Corrosion resulting from dissimilar metal contact.
Biological corrosion - Metal deterioration due to metabolic activity of microorganisms, such as Sulfate Reducing Bacteria or SRB's.
Cathode – (opposite of anode) The electrode of an electrolytic cell at which reduction is the principal reaction and electrons flow toward the cathode in the external circuit. Typical cathodic processes are cations taking up electrons being discharged, oxygen being reduced and the reduction of an element or group of elements from a high to a lower valence state.
Cathodic protection, or CP - A technique to reduce the corrosion rate of a metal by making it the cathode of an electrochemical cell. Accomplished utilizing paint, coatings, anodes, or ground beds and impressed current systems. Current systems use a negative charge to prevent corrosion.
Cation - A positively charged ion that migrates through the electrolyte toward the cathode under the influence of a potential gradient. See also anion and ion.
Cavitation corrosion –Cavitation caused by severe turbulent flow often leads to cavitation damage: May include loss of material, surface deformation, or properties or appearance changes.
Chloride – Major inorganic ion in all produced water acting as an electrolyte in the corrosion cycle. The greater the chlorides the higher the conductivity.
Copper Sulfate Electrode, CSE, or half-cell - Comprised of a piece of copper, a saturated solution of copper sulfate, and a porous membrane. The line of continuity goes from instrument to copper, copper to copper sulfate, copper sulfate to (salt bridge) to soil. (Farwest Corrosion Co.)
Corrosion - The chemical or electrochemical reaction between a material, usually a metal, and its environment that produces a deterioration of the material and its properties.
Corrosion-erosion - Corrosion that is increased because of the abrasive action of a moving stream; the presence of suspended particles greatly accelerates abrasive action.

Corrosion potential (Ecorr) - The potential of a corroding surface in an electrolyte relative to a reference electrode measured under open circuit conditions.
Corrosion product – Substance formed as a result of corrosion: Rust, Iron Oxide, Ferric Oxide
Corrosion protection - Modification of a corrosion system to mitigate corrosion damage.
Corrosion resistance - Ability of a metal to withstand corrosion in a given corrosion system
Corrosion Resistant Alloy, CRA - Nonferrous alloys where any one or the sum of the following alloy elements exceeds 50%: titanium, nickel, cobalt, chromium, and molybdenum.
Corrosion Resistant Material, CRM - Ferrous or nonferrous alloys that are more corrosion resistant than low alloy steels, includes CRA's, duplex, and stainless steels.
Corrosivity - Tendency of an environment to cause corrosion in a given corrosion system.
Crevice corrosion - Localized corrosion of a metal surface at or immediately adjacent to an area that is shielded from full exposure to the environment because of close proximity between the metal and the surface of another material.
Current - The net transfer of electric charge per unit time: amperes or amps, A.
Deposit - Foreign substance that comes from the environment, adhering to a material surface
Deposit corrosion - Localized corrosion under a deposit or material on a metal surface.
Dielectric Isolation – Isolating protected pipelines from non-protected pipelines.
Electrochemical cell - A system consisting of an anode, a cathode, a metallic contact, and immersed in an electrolyte. Anode and cathode may be different metals or dissimilar areas on the same metal surface.
Electrolyte – Soil or water that contacts both the anode and cathode in which the flow of current is accompanied by movement of matter.
Electromotive Force Series (EMF) - List of elements arranged according to their standard electrode potential; "noble" metals (gold) - positive, "active" metals (zinc) - negative.
Environmental cracking - Brittle fracture of a normally ductile material in which the corrosive effect of the environment is a major factor, including hydrogen embrittlement.
Faraday's law - The amount of any substance dissolved or deposited in electrolysis is proportional to the total electric charge passed.
Galvanic - The current resulting from the coupling of dissimilar electrodes in an electrolyte
Galvanic anode - A metal, which because of its relative position in the galvanic series, provides sacrificial protection to metals, that is more noble in the series when coupled in an electrolyte.
Galvanic cell - A cell in which chemical change is the source of electrical energy. It usually consists of two dissimilar conductors in contact with each other and with an electrolyte or of two similar conductors in contact with each other and with dissimilar electrolytes.
Galvanic corrosion – Accelerated, aggressive, and localized corrosion of a metal because of an electrical contact with a more noble metal or nonmetallic conductor in a corrosive electrolyte.
Galvanic couple - A pair of dissimilar conductors, commonly metals, in electrical contact.
Galvanic series - List of metals and alloys arranged according to their relative corrosion potentials in a given environment. Compare with electromotive series.
Galvanized steel - Steel coated with a thin layer of zinc to provide corrosion resistance in underbody auto parts, garbage cans, storage tanks, or fencing wire. Can be either hot dipped or electro galvanized.
General corrosion - Deterioration distributed more or less uniformly over a surface with little or know localized penetration, also known as uniform corrosion.
Half-cell - Electrode immersed in electrolyte designed for measurements of electrode potential.
Holiday – Defect or imperfection in pipeline coating detected utilizing a jeep, so called because of the sound made when holiday identification is discovered.
Hot dip coating - A metallic coating obtained by dipping the base metal into a molten metal.

Hot spot cp - Install at time of leak repair: 2” line - one 17 lb magnesium anode every 40 ft: 3” line - one 17# magnesium anode every 30’, 4” line - one 17 lb magnesium anode every 25’. Install extra anode at leak site.

Hydrogen embrittlement - Process resulting in a decrease of the toughness or ductility of a metal due to hydrogen (from H2S)being absorbed by solid metals.

Industrial atmosphere - An atmosphere in an area of heavy industry with soot, fly ash, and sulfur compounds as the principal constituents.

Inhibitor - Chemical substance(s) that prevent or reduce corrosion without significant reaction with the components of the environment.

Ion - An atom that has gained or lost one or more outer electrons and carries an electric charge.

Positive ions (cations) deficient in outer electrons. Negative ions (anions) excess outer electrons.

Localized corrosion - Corrosion at discrete sites: pitting, crevice, and stress corrosion cracking.

Mill Scale – Very brittle, Ferric Oxide layer formed during hot fabrication of metals.

Oxidation - (1) Loss of electrons by a constituent of a chemical reaction, or an increase in valence. (2) A corrosion reaction in which the corroded metal forms an oxide usually with.

Oxygen concentration cell - Galvanic cell resulting from difference in oxygen concentration between two locations.

Passivation - (1) A reduction of the anodic reaction rate of an electrode involved in corrosion. (2) The process in metal corrosion by which metals become passive.

Passivator - A type of inhibitor that appreciably changes the potential of a metal to a more noble (positive) value.

PH - Measure of the solution acidity or alkalinity; negative logarithm of the hydrogen-ion activity; it denotes the degree of acidity or basicity of a solution. 7.0 is neutral, below 7.0 increasing acidity; above 7.0 increasing alkalinity. Increasing corrosivity with decreasing ph. PH of 3.0 is 100 times more acidic than ph of 5.0 and 10 times more than a ph of 4.0

Pickling – treating a metal with mild acid bath to remove surface mill scale and rust

Pitting - Localized corrosion of a metal surface, confined to a point or small area that takes the form of cavities or pits. Most common form of corrosion due to incomplete chemical protective films, insulating, or barrier deposits of dirt, iron oxide, and foreign substances at pipe surface.

Polarization - Current flowing onto a steel pipeline results in the formation of a pipeline deposit consisting of calcium and magnesium hydroxides. The result is an increase in the pH at the soil to pipeline interface and the formation of a film of hydrogen on the pipeline surface.

Potential - Any of various functions from which intensity or velocity at any point in a field may be calculated or the driving influence of an electrochemical reaction.

Primer or prime coat - The first coat of paint applied to a surface. Formulated to have good bonding and wetting characteristics but may not contain inhibiting pigments.

Protective potential - Threshold value of the corrosion potential that has to be reached to enter a protective potential range, or the minimum potential required to suppress corrosion.

Rectifier ground bed – Anode bed with AC/DC power source used to protect pipelines.

Reducing agent - A compound that causes reduction, thereby itself becoming oxidized.

Reduction - A reaction in which electrons are added to the reactant, i.e., the addition of hydrogen or the abstraction of oxygen. Contrast with oxidation.

Reference electrode - A non-polarizable electrode with a known and highly reproducible potential used for potentiometric and voltammetric analyses. See also calomel electrode.

Rust - Visible corrosion product consisting of hydrated oxides of iron (Corrosion product)

Sacrificial protection - A form of cp accomplished by galvanically coupling it to a more anodic metal, typically magnesium or zinc.

Saturated calomel electrode - A reference electrode composed of mercury, mercurous chloride (calomel), and a saturated aqueous chloride solution.

Shop Coat – One or more coats of primer paint applied in the shop prior to shipping. Not intended for extended field use, should be painted with top coat as soon as possible.

Soil Resistivity – measured in ohm-centimeters, ohm-cm, measured utilizing a single probe, terminal, electrode, cane, pin, two-pin, or four-pin Wenner Method.

Stray-current corrosion - Corrosion resulting from direct current flow through foreign line crossing an existing protected system.

Steel – An alloy of carbon and iron with iron as the principal element at 97-99%.

Stress-corrosion cracking (SCC) - A cracking process that requires the simultaneous action of a corrodent and sustained tensile stress. May occur in combination with hydrogen embrittlement.

Sulfate Reducing Bacteria – SRB's are any organism that metabolically reduces sulfate to H_2S.

Thermite, or Cadweld - A process for making connections from prepackaged anodes to pipe.

Voltmeter – An instrument to measure pipe to soil potential

Wenner Four Pin Test Method - Test setup utilizes the mechanics of the "Four Electrode Method," which was developed by the National Bureau of Standards and is commonly known as the Wenner 4-pin Method. The resultant resistivity is the average resistivity of the soil (electrolyte) to a depth equal to the spacing between adjacent electrodes (soil pins). The maximum depth (pin spacing) of this standard test set has been designed for 20 feet, which is the recommended standard survey.

Recommended Web Sites for Corrosion Information
Corrosion - Leeward Community College, Hawaii, USA:
http://naio.kcc.hawaii.edu/chemistry/everyday_corrosion.html

Corrosion Basics - Corrosion Doctors, USA
http://www.corrosion-doctors.org/mod-basics.htm

Corrosion - Iverson Software Co., MN, USA
http://www.iversonsoftware.com/reference/chemistry/Corrosion.htm

Types of Corrosion - E/M Company Engineered Coating Solutions, USA
http://www.emcoatings.com/solved/corrosion/default2.htm

Corrosion: What is Corrosion? - Rebuild America Coalition, Washington, DC, USA
http://www.rebuildamerica.org/reports/corrosion.html

Corrosion - USGS, USA
http://wwwrcamnl.wr.usgs.gov/sws/cableways/corrosion.htm

Galvanic Corrosion - University of Delaware, USA
http://www.ocean.udel.edu/mas/masnotes/corrosion.html

Corrosionsource.com - The corrosion Portal
http://www.corrosionsource.com/index.htm

NACE Course: Cathodic Protection - Design I - five-day course, cp design, principles, methodology, and financial advantages in designing a system to include cp.
http://www.nace.org/naceframes/Education/edgenindex.htm

Companies that Provide Cathodic Protection Services:
http://www.delweg.com/cp/company1.htm

Glossaries:
http://www.delweg.com/library/exhibit/exbmain.htm
http://www.corrosionsource.com/handbook/glossary/
http://www.hghouston.com/glossary.html Corrosion Related Terms - The Hendrix Group, TX
American Iron and Steel Institute **http://www.steel.org/learning/glossary/g.htm**

Technical Information:
http://www.mesaproducts.com/

Deep Anode Ground-bed Design:
http://www.lidaproducts.com/technical/techmain.htm

Training:
http://www.delweg.com/cp/trainpos/cptrnmain.htm

Website Links for Vendor Information for Various Corrosion Related Products

Accurate Corrosion Control	Allied Corrosion Industries
Alltrista Zinc Products	American Construction & Supply
Anode Systems Company	Anotec Industries
ARK Engineering	Bass Engineering Co.
Borin Manufacturing	Brance-Krachy Co., Inc.
Brite Products	Brown Corrosion Services
Buried Pipeline Services	Cathodic Rectifiers
CC Technologies	Caproco
CLI International	Coastal Corrosion Control
Coffman Engineers	Concorr, Inc.
Corrosion Control, Inc.	Corrosion Control Products Company
Corrosion Control Systems	Corrosion Service
Corrosion Solutions, Inc.	Corrosion Testing Laboratories
Corrpro Companies, Inc.	CorrTech, Inc.
Cott Manufacturing	CP Masters, Inc.
CSIR North America	DACCO SCI, Inc.
Dairyland Electrical Industries	D C Corrosion Corp.
Edgewood Electric	EDM Services, Inc.
EDSI-Houston	Electrochemical Devices
ELK Engineering Associates	EnergySouth Corrosion Services
Farwest Corrosion Control Company	Galvotec Corrosion Services
Gerome Manufacuring	Graphtek LLC
Guardian Corrosion Control, Corp.	Hanson Survey and Design
The Hendrix Group	Henkels & McCoy
Holmberg Corrosion Control	Huron Tech
Innovative Corrosion Control	Integrity Inspection Services
J A Electronics	J&D Mechanical Industries
JET Drilling	Kadlec Associates
The Kehl Companies	Leigh Engineering
Loresco	M & B MAG
MATCO Associates	MATCOR
The Mears Group, Inc.	MESA Products, Inc.
Metretek, Inc.	M. C. Miller Co.
MSES Consultants	National Corrosion Service
Norcure	Northern Arizona Wind and Sun
Norton Corrosion Limited	Ormat
Raychem	J. D. Rellek Company
M. J. Schiff & Associates	Safe Engineering Services and Technologies
SESCO	Specialized Environmental Equipment
Southern Cathodic Protection	D. E. Stearns Stuart Steel Protection Corporation
Styco, LLC	Sullins International
Techni-Cor, Inc (TCI)	Tepsco, L.P.
Tierra Dynamic	Tinker & Rasor
Tinnea & Associates	Toal Associates, Inc.
Universal Rectifiers, Inc.	Universal Technical Resource Services, Inc.

Recommended Sources of Information

- Champion Technologies – Oil Field Corrosion Detection and Control Handbook - Free
- Appalachian Underground Corrosion Short Course, Morgantown West Virginia, Held annually in May, Total cost including room and board ~$500. Website is http://www.aucsc.com
- Peabody's Control of Pipeline Corrosion Fundamentals
- Guidance Manual for Operators of Small Natural Gas Systems, USDOT - Free
- Corrosion of Oil and Gas Well Equipment, API, 1990
- Oil and Gas Production Corrosion Control – Petroleum Extension Service of the University of Texas at Austin, catalog number 3.30110: ISBN 0-88698-110-7
- Pipeline Corrosion and Cathodic Protection, Gulf Publishing, M. Parker and E. Peattie
- SPE Reprint No. 46 - Corrosion

Paint Information and Guidelines

Paint Primer: One of the main defenses against corrosion is the regular and proper application of paint to most surface structures. Paint is effective due to its ability to isolate the structure from moisture and therefore stop the corrosion cycle. ***Proper surface preparation is essential to good painting results.***

Paint - Definition: The group of emulsions generally consisting of pigments suspended in a liquid medium for use as decorative or protective coatings.

History: Paint made its appearance about 30,000 years ago by cave dwellers. The first recorded paint mill in America was reportedly established in Boston in 1700 while in 1867, D.R. Averill of Ohio patented the first prepared or "ready mixed" paints in the United States. In the mid-1880s, paint factories began springing up in population and industrial centers across the nation. Virtually every product created on an assembly line makes extensive use of paints and coatings to beautify, protect and extend the life of the manufactured goods. Historically, the industry readily responded to environmental and health concerns by altering the chemistry of its products to control risks. Industry consensus standards limiting the use of lead pigments date back to the 1950s. The most frequently used steel primer paint in the nation until the mid 1970's was commonly known as Red Lead, and was outlawed because of the lead pigment. The replacement steel primer paint was known as Basic Lead Silico-Chromate consisting of a chromated lead silicate pigment dispersed in an alkyd resin vehicle. The paint was still easy to apply, it was very forgiving in terms of application oversights and a good durable coating was achieved. Over coats for this system were traditionally pigmented alkyd paints.

Major Paint Companies: Tnemec, Vanguard, Rustoleum, Sherwin Williams, Benjamin Moore, and Pittsburgh Paints.

From Pittsburgh Paints Performance Guide

Paint Composition: Paints consist of the following four basic components: Pigments, Binders, Solvent, and Additives.

Pigments: Particles used to give paints color, hiding power, and density. Typically white pigments are titanium dioxide, red pigments - iron oxide, yellow pigments - lead chromate, and green pigments– cobalt and chromium salts.

Binders: Bind pigments and additives together and provide resistance properties and adhesion to the substrate, or surface. Binders include Acrylic, Alkyd, or Epoxy resins.

Solvents: Cause the pigment and binder solids to behave as a fluid for application purposes and evaporate completely for all practical purposes. Solvents are typically aliphatic (mineral solvents) and aromatic hydrocarbons (toluene). Water and glycol solvents are used in water based or latex paints.

Additives: Special purpose ingredients to help paints perform better. Generally used in small amounts but contribute greatly to overall paint performance, including anti-skinning agents, mildewcides, coalescents, defoamers, thickeners, preservatives, and surfactants.

Gloss levels are categorized from Flat, Eggshell, Lo-Lustre, Satin, Semi-Gloss, to Gloss.

Paint types include latex, alkyds, epoxies, and aliphatic urethanes.

Latex paints: Synthetic resins, usually acrylic or vinyl acrylic, and are low in volatile organic compounds (VOC), low odor, fast drying, non-yellowing, and easy to clean up. Drying occurs when the water evaporates from the film allowing the coalescence of latex particles. Acrylics are used primarily to provide extra moisture resistance, wet adhesion, and color/gloss retention.

Alkyd paints are much harder than ordinary oils and drying occurs when the solvents evaporate from the film and the resin cures by oxidation. The drying action bonds a tough paint film to the applied surface.

Epoxy paints are tough two component finishes with outstanding hardness, abrasion resistance, alkali and acid resistance, and good adhesion when dry. The finish is smooth, easy to clean and lasts for years under the most severe conditions. Acrylic epoxies provide resistance to staining, yellowing, and scuffing of acrylic resins combined with the toughness and durability of epoxies.

Aliphatic Urethanes are two component products recommended for areas that demand superior chemical and stain resistance, plus superior gloss and color retention. The color and gloss retention and chemical resistance of acrylic urethane coatings will exceed those of more conventional high performance coatings.

Primer Selection

Primers are a vital component in a finished paint job looking good and performing as expected. Primers seal the surface, promote adhesion to the surface, block out stains, reduce surface preparation, and improve topcoat coverage. A primer helps paint from being absorbed unevenly. Specific primers can also provide corrosion resistance on metals. A primer should be used to repaint when the surface is uneven or badly deteriorated, jobs when the paint has been stripped or worn down to the original surface, on slick surface like tile and high gloss enamels, and on iron and steel that need protecting form corrosion.

General Surface Preparation

Good results and long paint life are more dependant on correct surface preparation for exterior painting than interior as a rule, but adequate surface preparation is important to both. *If basic problems are not corrected before the paint is applied, no paint will perform satisfactorily. Probably more than anything else, proper surface preparation is very important prior to painting. The performance of any paint or coating system is directly related to the quality and thoroughness of the surface preparation before painting.*

- Facility should be mowed prior to surface preparation
- Scrape and wire brush any loose material, paint, rust, debris
- Correct any moisture related problems
- Be sure surface is clean and dry.
- Remove mildew
- Remove gloss and chalking
- Temperature should be between 50 and 90
- Relative humidity should be below 85%.

SPE 84835

Identification of the Effects of Corrosion on Stripper Well Operations

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Abstract
This paper is the result of research to develop methodologies, diagnostic tools, and a procedure guide to identify the effects of corrosion on stripper well operations. Prior research performed for the Department of Energy determined that one of the major problems contributing to abnormal production decline in stripper gas wells was mechanical failure due to corrosion. The methodologies developed as a result of this study guide the stripper well operator to systematically identify cost effective corrosion mitigation procedures.

This case study includes more than 450 stripper wells located in the State of Ohio, although the methodologies developed are believed applicable to stripper wells in all geographical areas.

The prior study and identification of the corrosion control problem indicated that many operators fail to recognize and evaluate the economics of proper corrosion mitigation methods to stripper wells, resulting in additional expense and prematurely abandoned wells. Experience indicates that due to the marginal production associated with stripper wells, the correction of mechanical failures due to corrosion is even more problematic later in the life of wells when capital expenditures for repairs of any nature are often cost prohibitive. The current study revealed that although the subject of corrosion is very complex, stripper well operators can benefit through the simple application of planning, painting, and plastics. Therefore, it was the goal of the of this research program to develop an application guide detailing cost effective corrosion mitigation procedures.

The systematic methodology developed benefits every producer by increasing the efficiency of problem assessment and implementation of corrosion solutions, ultimately resulting in increased production, reserves, and profitability of stripper wells.

This study was specifically developed for stripper well operators in a cost-sharing venture between James Engineering, Inc., the Stripper Well Consortium, and the National Energy Technology Laboratory under the Subcontract No. 2283-JE-DOE-1025.

Introduction
Prior research performed for the Department of Energy found that 270 of 376 wells evaluated, or over 70%, exhibited some form of abnormal production decline during the past five years. Nearly 23% of the 270 abnormal production declines were caused by mechanical failure due to corrosion, which resulted in both decreased reserves and revenue. Even though corrosion has been historically evident throughout all phases of the production process, the frequency of mechanical failures due to corrosion represents a significant opportunity for improvement. Through the proper application of corrosion identification and mitigation practices, stripper well operators can better maintain mechanical integrity, economically remediate corrosion affected wells, and minimize premature abandonment.

The prior research indicates that stripper well operators often fail to properly evaluate the economics of corrosion mitigation over the entire life of the well, even when the problems are recognized. The current study found that all wells experience corrosion and that failure to maintain an adequate corrosion mitigation program resulted in decreased equipment value, decreased mechanical integrity, added expense, loss of product, potential environmental impact, and loss of wells. Current study results also indicate that many of the corrosion mitigation methods utilized by large oil and gas production companies, gas transmission companies, and gas storage companies are cost prohibitive for most stripper well operators. However, due to lack of training, over a decade of low product prices, and the marginal production associated with stripper wells, many stripper well operators fail to employ consistent, available methodologies to address historical corrosion problems leaving the effects of corrosion unrecognized or un-addressed.

Stripper well operators are faced with multiple challenges in operating stripper wells and corrosion is often not a pressing concern until mechanical failures occur. These challenges include multiple managerial duties, limited staffs, marginal production, aging wells, and the multiple ownership of wells accompanied with a broad range of associated problems. Generally with ownership changes, stripper well operators are left with consolidating a hodgepodge of wells with previous attempts at production or corrosion prevention, requiring a considerable effort just to restore wells to daily operation. In spite of the many obstacles, stripper well operators must be able to quickly identify and focus on areas where corrosion poses the greatest threat.

Stripper wells are defined as those wells with production less than or equal to 60 mcfd or 10 bopd, while the national average is significantly less at 15 mcfd and 2 bopd. The Appalachian Basin represents 205,000 of the nation's 646,000 stripper wells, but the average stripper well in the Appalachian Basin only produces 11 mcfd and 0.4 bopd. So even when stripper well production is maximized, the amount of capital available for repairs or enhancements is limited.[ii]

Therefore, it is absolutely necessary that the corrosion mitigation methods employed by stripper well operators be effective, economical, and easy to implement. The procedure guide developed as a result of this study provides methods for identifying and selecting corrosion mitigation techniques for primary production stripper wells.

Theory

James Engineering, Inc. proposed to study the major factors affecting corrosion in stripper wells that lead to mechanical failures, and to determine the appropriate application of corrosion mitigation technologies. The goal of the study was to develop a procedure guide detailing selective procedures for cost effective corrosion mitigation procedures and operating practices using data collection forms and decision trees.

The study included the following:

- Perform a literature search
- Develop data collection forms
- Perform a field review
- Summarize the results of the field review
- Develop decision trees to identify and implement corrosion mitigation
- Test the decision tree analysis
- Prepare a procedure guide
- Transfer the technology

Perform a Literature Search

The literature search identified numerous books, papers, articles, and information related to corrosion and corrosion mitigation. The search included the SPE website, the Internet, the Marietta College Library, the American Petroleum Institute, the National Association of Corrosion Engineers (NACE), the Appalachian Underground Corrosion Short Course, and the South West Petroleum Short Course CD paper database.

Several key words for the searches included corrosion, corrosion mitigation, cathodic protection, painting, types of corrosion, and plastics.

Of particular interest were a paper written by Harry Byars in 1961 entitled "Patches on our Oil Patch Pockets" and a 2002 study published by the NACE entitled "Corrosion Costs and Preventive Strategies in the United States" . Mr. Byars' paper alluded to the general poor condition of the oil industry in 1961 due solely to the effects of corrosion. The 2002 NACE study stated, "the materials and corrosion control technologies used in the traditional onshore production facilities have not significantly changed since the 1970's." This information indicates that 1.) The corrosion problem for stripper well operators is not a new one, and 2.) Corrosion control methods have not changed significantly in over thirty years. However, stripper well operators still struggle with the identification and application of effective corrosion mitigation methods.

In addition to the literature search, interviews were completed with a large independent producer, three major oilfield supply companies, a plastic tank distributor, and two paint company representatives. Further inquiries were made to several companies on operating practices, and a corrosion company was contracted for corrosion mitigation recommendations. Additional information was gathered at a PTTC Produced Water Seminar, a cased hole logging seminar, and a PTTC Corrosion Management Workshop.

The literature search, interviews, and seminars not only identified the costs of corrosion, but also identified the basics of corrosion: definition, components, chemistry, electrode potential, types, and primary agents, corrosion identification methods, soil assessment methods, corrosion mitigation methods, and the importance of field personnel.

The Cost of Corrosion

The study identified the direct and indirect costs associated with corrosion, the 2002 NACE corrosion study, Artex Oil Company's corrosion related capital expenditures, and the economics of corrosion.

Corrosion results in the direct costs of repair or replacement of casing, rods, tubing, separators, production tanks, pipelines and corrosion inhibition, and in the indirect costs of lost or deferred production, lower equipment salvage values, environmental damage with associated penalties, and decreased safety.

Research identified a 2002 study entitled "Corrosion Costs and Preventive Strategies in the United States", initiated by NACE International, mandated in 1999 by the U.S. Congress, and conducted by CC Technologies Laboratories, Inc. of Dublin, Ohio determined the cost of corrosion control methods and services, the economic impact of corrosion for specific industry sectors, extrapolated individual sector costs to a national corrosion cost, assessed barriers to effective implementation of optimized corrosion control practices, and developed implementation strategies and cost-saving recommendations.

The 2002 NACE study identified that the petroleum industry spends millions of dollars every year developing new oil and natural gas reserves, and yet additional millions are spent maintaining existing production facilities from the effects of corrosion. The NACE study estimated that all United States industries combined spend $276,000,000,000 annually on corrosion. It is estimated that the onshore oil and gas industry alone spends over $300,000,000 per year. The effects of corrosion are so extensive that the replacement of corrosion damaged materials alone accounts for approximately 20% of the annual iron produced in the United States.

The 2002 NACE study suggested the following preventative strategies to impact the corrosion costs associated with the oil and gas industry: Increase consciousness of corrosion control costs and potential savings, change the perception that nothing can be done about corrosion, advance design practices for better corrosion management, change technical practices to realize corrosion cost savings, change management policies to acknowledge that throwing money at the problem after the leak occurs should not be considered a cost-effective strategy, advance life prediction and performance assessment methods, advance technology through research, development, and implementation, and improve education and training for corrosion control.[iii]

A review of the Artex Oil Company's capital expenditures for the five-year period of 1998 - 2002 identified the capital expenditures to correct corrosion related problems. The review categorized the effects of corrosion into downhole casing leaks (CL), pipeline repairs (PL), top joint tubing change outs (TJ), wellhead repairs or leaks in the production casing in the wellhead area (WH), production storage tank repairs (TR), and general facilities costs (GF), see Table 1.

Table 1
Corrosion Related Problems - Artex Oil Company

Category	**CL**	**PL**	**TJ**	**WH**	**TR**	**GF**
No.	40	124	9	27	15	12
No, %	18%	57%	4%	12%	7%	5%
Total, M$	**$446**	**$168**	**$42**	**$24**	**$12**	**$6**
M$, %	64%	24%	6%	3%	2%	1%
Avg, M$	**$11.4**	**$1.4**	**$4.7**	**$0.9**	**$0.8**	**$0.5**

Two hundred and twenty-seven corrosion related incidents were identified at a cost of $696,900, or an average of $3,125 per incident. These total incidents represent an average occurrence of one out of every two wells operated over the five-year period. Table 1 identifies the distribution by category of the number of incidents, the percentage the number represents of the total incidents, the total cost, and the average cost per incident. The above costs are for repairs only and do account for the costs of lost production or reserves.

The forty downhole casing leaks represent 18% of the total incidents, 64% of the total costs, and averaged $11,400 per incident. Casing leaks generally originate on the exterior of the casing near hydrogen sulfide bearing limestone or exposed coal seams. These casing leaks normally represent the loss of the well due to the influx of water and loss of production unless repaired. Casing repair costs include service rig time, packer, tubing, clean out, swabbing, dozer, company supervision and may include the installation of a second string of tubing, rods, pump, and pumping unit. Chemical inhibition is effective in mitigating downhole casing leaks, however, primary cementing over the H_2S or coal interval is the preferred method.

The one hundred twenty-four pipeline repairs represent 57% of the incidents, 24% of the total costs, and averaged $1,400 per incident. Experience indicates that the leaks originated on the exterior of the pipeline. While an occasional gathering system leak is to be expected, the total number of leaks indicates significant opportunity for improvement. The pipeline leaks include production line leaks with associated oil spills. Stripper well operators generally continue to operate existing production lines and gas systems until mechanical failures occur. Repairs are then made utilizing clamps, joint replacement, or full replacement with plastic lines.

To better understand the pipeline expenditures a summary was prepared of the gas gathering system associated with approximately 120 wells, see Table 2. The summary identified a total of 369,400' of pipeline with five different diameters comprised of both steel and plastic. The summary is representative of similar systems many stripper well operators maintain as a result of acquisition consolidation.

Table 2
120 Well Gas Gathering System Summary

Type	**Steel**				**Plastic**		
Size	6"	4"	3"	2"	3"	2"	1 ½"
M Ft.	27.6	105.6	50.0	72.6	23.0	79.6	11.0
%	8%	28%	14%	20%	6%	21%	3%

The nine top joint tubing replacements represent 4% of the incidents, 6% of the total costs, and averaged $4,700 per incident. These leaks originate on the exterior of the tubing occurring near the packing. Corrosion occurs circumferentially until insufficient material remains to maintain mechanical integrity and repair is necessary for continued operation of the well. The corrosion is due to localized corrosion caused by the accumulation of rain in the packing area, and aggravated by chlorides in the produced fluids. Regular painting can minimize this type of corrosion.

The twenty-seven wellhead casing leaks represent 12% of the incidents, 3% of the total costs, and averaged $900 per incident. These leaks originate on the exterior of the casing, result in pressure and product loss, and require repair for continued well operation. The location of the leak is at or near the packing and is due to atmospheric corrosion, the accumulation of rain in the packing area, and is aggravated by chlorides in the produced fluids. Casing repair costs include service rig time, welder, company supervision, and the temporary installation of a packer just below the affected area during the repair. Regular painting can minimize this type of corrosion.

The fifteen tank repairs represent 7% of the total incidents, 2% of the total costs, and averaged $800 per incident. Tank failures affect well operations by lost production and environmental liability. Tank corrosion can be internal or external, occurring in the top, sides, bottom, or heater tube and is normally due to insufficient maintenance and coating, improper setting, atmospheric conditions, and the fluids stored. Corrosion is aggravated by leaking valves, connections, and tank inlet lines. Corrosion is easily identified and corrected on the tank exterior, but are not for the tank interior and bottom. Experience indicates that the bottom of the tank represents the most significant area affected by leaks that require immediate attention. Painting, proper tank setting, and the application of coal tar to the tank bottoms are effective corrosion mitigation methods for steel tanks. The use of plastic tanks for storage of brine significantly reduces the effects of corrosion and is a common practice for many stripper well operators. Table 4 identifies the distribution of the 835 tanks for Artex Oil Company.

Table 4
Tank Size and Type Distribution

Size, barrels	210	100	50	35	25	Cmt Vaults
No.	**116**	**477**	**166**	**15**	**35**	**26**
% of Total	14 %	57 %	20 %	2 %	4 %	3%

The twelve general facilities repairs accounted for 5% of the total incidents, less than 1% of the total costs, and averaged $500 per incident. The general facilities category accounted for the remainder of corrosion related incidents including valves, gas sales meters, etc. Many valves do not receive regular maintenance, become corroded, and are impossible and dangerous to operate or replace.

General Corrosion Related Economics

Lost production income due to corrosion can often outweigh the expenses associated with regular maintenance. For example, a 5-mcfd loss due to corrosion in an aging gathering system at $5.00 per mcf represents a loss of $9,000 per year. A five-barrel oil spill due to corrosion could cost $5,000 to remediate, with the majority of the cost associated with spill clean up rather than the line or tank repair. Stripper well operators should seriously consider the potential benefits of regular corrosion maintenance, line replacement, and the identification of specific wells or lines where corrosion could have environmental impact. Specific areas for line replacement may include those near streams and lakes, or lines where fluid is pumped up a hill. The lost opportunity costs, time and effort addressing leaks, which could have been spent increasing production or addressing other issues must also be considered.

The Basics of Corrosion

Corrosion Defined

Corrosion is defined as "the deterioration of a material, usually a metal, due to a reaction with its environment." In regards to oilfield operations, corrosion generally involves carbon steel reacting with soil, water, moisture, oxygen, carbon dioxide, and/or hydrogen sulfide, resulting in the formation of rust. When observed with the naked eye, rust appears to be very commonplace, but is actually the product of very complex electrochemical reactions that require four components to occur.

The Components of Corrosion

The four required components for a corrosion cell are an anode, a cathode, a metal path, and an electrolyte.

The anode is always where corrosion occurs. The anode is where electrons are lost, metal is dissolved, and current leaves the metal and enters the electrolyte. The cathode is where no corrosion occurs, current is picked up, and rust deposits occur. The metal path connects the anode and the cathode allowing electrons to flow. The anode, cathode, and metal path are generally located on the surface of the individual grains of steel. The electrolyte is a conducting medium for metal ions and current flow, present as water in the soil or moisture in the atmosphere as rain, dew, or humidity.

The Chemistry of Corrosion

It is well established that the corrosion of buried metallic structures such as pipelines is associated with: 1.) the flow of electricity, and 2.) the chemical interaction between the metal and the surrounding soil, or an electrochemical reaction.

The amount of electricity flowing in the corrosion cell is directly related to the amount of metal being removed and the number and size of the anodic and cathodic areas on the steel. The chemical reactions of oxidation and reduction occur in the anodic and cathodic areas respectively.

Anodic and cathodic areas are created during refining and fabrication affecting the metallurgical properties of the steel, and further affected by field operating factors. It is important to recognize that fabrication does not result in a solid steel product with uniform properties, but a conglomeration of unique grain structures with a natural tendency to exchange ions from one grain to another.

Some refining factors leading to grain structure variations include dirty steel, improper heat treatment, improper stress relief, and inadequate melting sequences, while fabricating factors include folds, seams, inadequate heat treatment, inadequate cleaning of mill scale, improper welding, excessive cold straightening, and general surface damage. Field operating factors include additional surface damage, improper welding, cold bending, acidic water, water deposited scales, and corrosion product scales.

The oxidation and reduction reactions that explain the corrosion of steel starts with a transfer of electrons. First, metal loss begins to occur at anodic areas when atoms of iron, Fe^0, go into solution as Fe^{++} ions in the electrolyte, according to the formula $Fe^0 \rightarrow Fe^{++} + 2e^-$, or oxidation. Then the rate of corrosion slows as Fe^{++} ions accumulate near the anodic surface until precipitated as rust product due to the presence of oxygen allowing the corrosion process to continue. The electrons, e^-, released from the atoms of iron, Fe^0, flow through the metal path creating electricity until their charge is neutralized through reduction with hydrogen or oxygen ($O_2 + 4H^+ + 4e^- \rightarrow 2\ H2O$ or $O_2 + 2H_2O + 4e^- \rightarrow 4OH$).

Simply stated, corrosion is the release of the energy required to convert iron ore (iron oxide) into steel, that is, there exists a natural tendency for iron ore to return from its higher energy state as steel to its lower energy state of native iron ore as rust (iron oxide). The essential difference between ordinary steel and pure iron is the carbon content from low with 0.3% carbon to ultra high with 1.2% – 2.0% carbon.

Electrode Potential of Anodes and Cathodes

Similar to the differences between grains of the same material, when two metals are connected in an electrically conducting environment, they react by forming a galvanic corrosion cell. The driving force behind the rate of these reactions is related to the electromotive force (EMF) potential of the materials involved, measured in volts. The materials involved in a galvanic cell tend are either more noble (cathodic) or less noble (anodic). Table 1 identifies the EMF for some of the more common metals (after AUCSC Intermediate Course, Table 1-1). Note that a material may be anodic to one material, but cathodic to another depending on its location in the table.

Table 1 EMF Table of Potentials

More Anodic More Corrosive More Noble	**Material**	**Emf, V**
	Potassium	-2.92
	Barium	-2.90
	Calcium	-2.87
	Sodium	-2.71
	Magnesium	-2.40
	Aluminum	-1.70
	Manganese	-1.10
	Zinc	-0.76
	Iron (Ferrous)	-0.44
	Nickel	-0.23
	Tin	-0.14
	Lead	-0.12
	Iron (Ferric)	-0.04
	Hydrogen	0.00

More Cathodic Less Corrosive Less Noble	Copper	+0.34
	Silver	+0.80
	Platinum	+0.86
	Gold	+1.36

Primary Agents of Corrosion

The primary agents that affect oilfield corrosion are oxygen, carbon dioxide, hydrogen sulfide, hydrochloric acid, organic acids, and chlorides. Factors affecting the rate of corrosion include temperature (>150°), pH, bacteria, and environment. The rate of corrosion generally increases as the concentration of these factors increases, with the exception of pH, which becomes more corrosive as it decreases.

Types of Corrosion

Because the categories of corrosion vary according to specific industries, for the purposes of our study, corrosion was divided into two fundamental types: general and localized. General corrosion is characterized by a uniform layer of corrosion, or metal loss, with no pitting. Localized corrosion was further categorized as galvanic, pitting, crevice, inter-granular, stray current, microbiologically induced, de-alloying, erosion, and stress. Localized corrosion may occur as a combination of any of the previously mentioned categories.

Galvanic corrosion occurs due to the EMF difference between two different materials. Pitting corrosion is confined to a small area and is evidenced by cavities or holes produced in the materials that are either trough shaped or sideways pits. Corrosion product or rust generally covers most pits. Crevice corrosion occurs in shielded areas under gaskets, washers, insulation material, fastener heads, surface deposits, disbonded coatings, lap joints, and clamps due to changes in the local chemistry. Intergranular corrosion is localized attack along the grain boundaries, or immediately adjacent to grain boundaries, while the bulk of the grains remain largely unaffected. Stray current corrosion occurs when a foreign line crosses another line cathodically protected by impressed current, is very aggressive, and mechanical failure can occur in days rather than months or years. Microbiologically induced corrosion (MIC) is corrosion initiated by the presence of microorganisms, bacteria or fungi and often results in pitting and crevice corrosion. Oil transport lines and waterflood operations often have to address MIC. The remaining forms of corrosion; de-alloying, erosion, and stress, do not appear to be major factors in stripper well operations**.**

Corrosion Identification Methods

Corrosion identification methods include visual inspection, physical observation, pressure and production monitoring, electronic inspection, soil analysis, chemical analysis, and metal coupon analysis.

Visual inspection is limited to external surfaces, but is beneficial to stripper well operations due to the low cost and general effectiveness. Visual inspections identify potential problems with wellheads, exposed sections of casing and tubing, separators, production units, meters, storage tanks, and surface lines. Well tenders or production managers should complete visual inspections for prioritizing maintenance, repairs, or replacements.

Physical observation identifies corrosion resulting in the loss of pressure and product in wellheads, tanks, or pipelines. Well tenders, landowners, and production variance reports assist in identifying mechanical failures. Physical signs of a natural gas leak include an odor, a hissing sound, dirt or water being blown into the air, bubbling in wet areas, patches of dead vegetation, fire burning above the ground, dry spots in moist fields, areas of abnormally hard or dry soil, or a white vapor cloud close to the ground. Oil spills are generally identified as seepages or as rainbow sheens.

Well tenders often identify mechanical failures through monitoring operating pressures and production volumes. Decreases in normal operating pressures may indicate a casing or pipeline failure while decreases in gas production or increases in fluid production often indicate a casing failure.

Electronic inspection allows for the review of the internal surfaces of production casing and pipelines. Large production companies, gas transmission companies, or natural storage companies utilize electronic logging to regularly monitor casing and pipelines to identify pitting or general corrosion for corrective action prior to catastrophic mechanical failure. Stripper well operators generally rely on the more cost effective methods of prevention or repair, rather than incur the expense of electronic inspection.

The electronic identification equipment used by stripper well operators includes portable gas detectors, pipeline locators, gps units, and portable gas analyzers. Electronic gas detectors identify gas leaks even when an odor is not perceived. Pipeline locators identify the location of steel pipelines and the tracer lines installed with plastic pipelines. Gps units identify pipeline routes and leak locations in remote areas for later repair or maintenance. Portable gas detectors are also helpful in determining the presence of H_2S or CO_2. An H_2S concentration of 250 ppm or more and ph of 6.5 or less indicates a corrosive environment. For CO_2, a 7-psi partial pressure with a ph of 7 or less, and a count of 100 ppm or greater indicates a corrosive environment.

Soil analysis identifies the conductivity of the soil to determine the potential corrosivity. This testing can be accomplished in-house with some training by stripper well operators, but is generally too expensive to contract out to experienced companies. Due to the complex nature of this subject, further discussion is addressed as a separate subject under soil assessment methods.

Chemical analysis, performed by trained oilfield chemical company personnel, identifies potentially corrosive elements in a production stream. Specifically, chemical analysis typically identifies the presence and concentrations of iron, sodium, potassium, calcium, magnesium, chlorides, sulfates, carbonates, resistivity, hydrogen sulfide, pH, and total dissolved solids. The increased concentration of these factors generally increases the corrosive environment with the exception of ph. Continuous monitoring of fluids is required for waterfloods due to the interaction of injected water and reservoir fluids.

ph is defined mathematically as the negative logarithm (base 10) of the hydrogen ion and is calculated in powers of 10, that is, a solution with a ph of 1.0 is 10 times greater than one with a ph of 2.0. Significant corrosion is unlikely where water or soils have a ph higher of 7 or higher, alkaline. However, as the ph lowers from 7 corrosion increases greatly. Any ph of 6 or less will provide an environment for the occurrence of significant corrosion and probable pitting.

Corrosion coupons identify internal pipeline corrosion by providing a quantitative measurement of metal loss in millimeters per year (mils per year, or MPY). Pre-weighed coupons are put in line, left for one month to one year, removed, and analyzed. Coupons are then photographed, cleaned, visually inspected, dried, re-weighed, and re-photographed. The corrosion rate is then estimated based upon the weight of coupon material lost. Champion Technologies recommend that a coupon test of less than 5 MPY and no pitting indicates corrosion is unlikely, less than 5 MPY with pitting indicates isolated corrosion, while greater than 5 MPY indicates active corrosion. Further, the most frequent causes of pipeline internal corrosion is improper welding, too high or low of velocity, inadequate pigging leading to scale buildup, liquid buildup, and bacteria growth, or use of the wrong inhibitor.

It is important to document all analyses, visual identifications, observations, and leak repairs to assist in the mitigation of future mechanical failures.

Soil Assessment Methods

Measuring resistivity is important to identify pipeline soil resistivity variations, since steel pipelines are susceptible to galvanic corrosion due to soil resistivity variations. Pipeline portions with lower soil resistivities become anodic relative to other portions of the pipeline, and therefore corrode.

Soil resistivity, measured in ohm-centimeters, is the accepted industry standard as the primary indicator of soil corrosivity. As soil resistivity decreases, current flows easier through the soil. Soil resistivity is a function of the moisture content, soil temperature and soil type, Table 2.

Increased moisture or electrolyte (brine) content decreases resistivity, Table 3, with soils below 10,000 ohm-cm indicating rapid and severe pipeline deterioration. Resistivity increases substantially when moisture content falls below 10% or temperatures fall below freezing. High organic soils have low resistivity and retain high moisture levels. Sandy soils drain faster, have lower moisture content, and higher resistivity, while solid rock has little moisture and high resistivity.

Table 2: Soil Resistivity as a Function of Soil Type	
Soil Type	**Ohm – Cm**
Well graded gravels	60,000 – 100,000
Poorly graded gravels	100,000 – 250,000
Clayey gravel	20,000 – 40,000
Silty sands	10,000 – 50,000
Clayey sands	5,000 – 20,000
Silty or clayey fine sands	3,000 – 8,000
Fine sandy or silty soils	8,000 – 30,000
Gravelly clays	2,500 – 6,000
Inorganic clays	1,000 – 5,500

Table 3 – Soil Resistivity as a Function Of Moisture Content and Soil Type			
Moisture Content (%)	**Top Soil**	**Sandy Loam**	**Red Clay**
	Ohm-cm	**Ohm-cm**	**Ohm-cm**
2		185,000	
4		60,000	
6	135,000	38,000	
8	90,000	28,000	
10	60,000	22,000	
12	35,000	17,000	180,000
14	25,000	14,000	55,000
16	20,000	12,000	20,000
18	15,000	10,000	14,000
20	12,000	9,000	10,000
22	10,000	8,000	9,000
24	10,000	7,000	8,000

Soil Resistivity Measurement

The most common methods to analyze soil resistivity are the Wenner four-point method, the three-point method, the two-point method, and the copper-copper sulfate reference electrode. The Wenner four-pin method measures the average resistivity of large volumes of soil based on the spacing of the measuring pins. Readings are typically taken every 400 feet over the length of pipeline by a two to three man crew.

One of the most common methods to measure structure to soil resistivities utilizing a voltmeter and the copper–copper sulfate electrode (CSE). The positive terminal of the voltmeter is connected to the CSE reference electrode and the negative terminal to the pipeline, tank, or other structure. Pipe to soil potentials are generally negative under corrosive conditions when measured with a CSE. Digital meters, rather than analog, are recommended due to their ease of use and resistance to damage if the polarity is reversed.

In summary, soil resistivity measurements provide a direct indication of the corrosive properties of soil. Soils with resistivities of 50,000 to 100,000 ohm-cm are mildly corrosive; 30,000 to 50,000 are moderately corrosive, and those with less than 30,000 ohm-cm are very corrosive.

Stripper well operators usually find contracted services to conduct soil resistivity measurements cost prohibitive but can be completed by in-house personnel with nominal training. The general condition of most gathering system right of ways, un-mowed and unmarked, increase the time required for soil resistivity surveys. An estimated cost for a three-man soil survey crew for one mile is approximately $1,000 per day.

Common Methods of Corrosion Control

The most common methods of corrosion control are cathodic protection, coatings, corrosion resistant materials, insulating joints, and chemical inhibitors.

Cathodic protection reduces pipeline corrosion rates by utilizing sacrificial anodes or rectifier ground bed systems to make the pipeline cathodic. Cathodic protection allows other materials to corrode, become anodic, and pipeline anodic areas to be protected. The current requirements for pipeline corrosion protection are reduced through the coatings. Cathodic protection requirements are established through soil resistivity measurements taken before and after pipeline and cathodic protection system installation. Stripper well operators typically do not utilize soil testing but some other method based on experience to determine cathodic protection requirements.

Sacrificial anode systems accomplish protection by coupling a magnesium or zinc anode to the pipeline for current to flow from the anode to pipeline, progressively destroying (sacrificing) the anode and protecting the pipeline. Typical anode sizes are either 17 or 34 pound. Sacrificial anodes can be used for hot spot protection on previously unprotected lines, and is effective when replacing line sections or applying repair clamps. Sacrificial anode advantages include no external power required, low voltage output, no voltage variance, easy installation, location adaptable, no maintenance required, and no inspection required. One disadvantage is that too many anodes are required for adequate protection of new bare steel lines.

Cathodic protection rectifier ground bed systems include an AC power supply, a rectifier unit, a ground bed of anodes, connecting cables, and the pipeline. The rectifier utilizes a transformer to step down high AC line voltage to low AC voltage, then utilizes a rectifying element to converts the low AC voltage to DC which is transferred by a single cable to a high silicon iron or graphite anode ground bed located 150 to 450 feet from the pipeline. Rectifier ground bed system advantages include variable D.C. voltage application, protection of bare steel lines, and automation for varying moisture conditions. Disadvantages include possible foreign structures interference, unintentional current interruption, required regular maintenance, and higher operating costs.

All coating systems are susceptible to defect, but are for most part very effective in corrosion prevention. Coatings for cathodic protection for most surface equipment include the application of primer and paint. Coatings should be inspected annually, while well tenders should casually inspect the facility with every visit. Any coating defects should be addressed as soon as possible, or noted for the annual maintenance program. Once a facility has been properly coated, repainting should not be necessary for at least five to ten years except in extreme conditions. Wax coatings are also used to minimize wellhead fluid contact

Pipelines are corrosion protected to ensure reliable service over a long time. Coating systems include a one-coat epoxy, a two-layer system of adhesive and polyethylene topcoat, and the three-layer system of epoxy powder, adhesive, and polyethylene topcoat. Pipeline coatings are most effective when installed in combination with cathodic protection due to the defects associated with all coatings.

Experience indicates that stripper oil and gas operators can generally achieve good success utilizing either plastic pipe, or a combination of coated pipe and sacrificial anode system for protecting most small diameter (2" – 4"), low-pressure (5 – 250 psi) gas gathering systems. Larger diameter (>4"), high pressure systems (>250 psi) should be reviewed for the relative benefits of utilizing an impressed current over the sacrificial anode system. Existing systems without coating or cathodic protection will benefit by the application of hot spot protection during repairs or replacements.

Corrosion resistant materials can be non-metallic or corrosion resistant alloys. Materials utilized for stripper well applications include plastic, stainless steel, and fiberglass, while plastic is the predominant product of choice for both fluid storage tanks and pipeline material. General limiting factors in applying plastic are its maximum pressure rating, temperature rating, and susceptibility to damage during installation or by offset construction. Plastic is also utilized for lining tubing or coating packers in corrosive downhole environments. Stainless steel needle valves are used extensively throughout the industry for pressure gauges. Fiberglass use has diminished due to the limited number of manufacturers and the superior attributes of plastic.

Insulating joints are used to interrupt current flow and are typically inserted between protected and unprotected pipelines. This type of corrosion control is utilized to limit cathodic protection, reduce the effects of stray currents, and to separate dissimilar metals. Insulating joints are typically a requirement by most gas transmission companies between their lines and a stripper well operator's gas gathering system.[iv]

By definition, chemical inhibitors are added in a small concentration to an environment to effectively reduce the corrosion rate of the exposed metal in that environment. Chemical inhibitors types include passivating, cathodic, organic, precipitation, and volatile corrosion inhibitors. Inhibitors are oil soluble, oil soluble brine dispersible, water-soluble, oxygen scavengers, and surfactant based. Application areas include tubing, gathering systems, water disposal lines, oil or water storage tanks, and gas sweetening or dehydration units. Treatments can be by batch or continuous injection with batch injections varying from every two weeks to three months. Chemical treatments, generally effective only on internal corrosion, can be effective on external corrosion control of wells with H_2S.[v]

The Importance of Field Personnel

Experience and results of the study show that field personnel are the primary line of defense in corrosion identification and mitigation. The API Corrosion of Oil Well Equipment Handbook identified three critical areas for field personnel: corrosion problem recognition, record keeping, and carrying out control procedures. Well tenders and field personnel will normally observe preliminary indications of corrosion leading to mechanical failure and can advise management on maintenance or repair requirements, therefore, it is important to provide appropriate training to be able to identify conditions that aggravate corrosion.

Data Collection Form Development

One form was developed to identify the most common areas of corrosion for stripper well operators based upon literature review results and the analysis of Artex Oil Company's capital expenditures related to corrosion. The data collection form was developed to use during the field review and for use later by stripper well operators to evaluate the effects of corrosion on surface facilities. The form provides a systematic means of assimilating data to identify and evaluate the most common areas of stripper well corrosion and corrosion mitigation methodology, and was designed for completion by either field or office personnel. A goal of the form is to provide sufficient information to assist production managers in allocating financial resources and scheduling annual maintenance.

The four part form addresses wellheads, casing, tubing, production storage tanks, pipelines, and surface facilities. Part 1 addresses general information, Part 2, specific identification and description, Part 3, corrosion correction method, and Part 4, comments.

Part 1, general information, identifies the area to be inspected (Lease, Pipeline, or Other), the person completing the inspection, the date of inspection, the GPS location number, and the photograph identification numbers.

Part 2, identification and description, identifies the specific review area, the visual extent of the corrosion classified either as minimal, moderate, or severe, the type and cause of the corrosion, a brief description of the corrosion, and the correction recommended. Common areas of corrosion for review include downhole production casing and tubing, wellhead side nipples and valves, top joint casing and tubing, pipelines, master valve, needle valves, other valves, production tanks (210 bbl, 100 bbl, or 50 bbl), fittings, production unit, separator, riser, vent, or pipeline marker, ladder, casing plunger or tubing plunger lubricator, plunger, or pumping unit.

Part 3, methods of correction, includes cleaning, protecting, repairing, or replacing. Cleaning methods include sandpaper, sand blasting, high pressure washer, scraper, and wire brush. Protection methods include painting (primer and topcoat), insulating, or installation of a dielectric flange. Repair methods include tightening, clamping, top joint of casing repair, top joint of tubing replacement, or downhole packer installation. Replacements include pipeline sections, fittings, vales, controls, or slip lining plastic line inside existing steel lines. Tank correction includes replacement of same type and size of tank, removal of tank, or replacement of a steel tank with a plastic or fiberglass tank. All methods of correction were number coded for ease of use.

Part 4 provides a section for noting any additional comments regarding corrosion inspection, maintenance, repair, or replacement.

Perform Field Review

A field review was completed of several well tenders routes accounting for more than 200 wells. The review included visual inspection of most wells and associated surface facilities. The goal of the field review was to gather information regarding the effects of corrosion on stripper well operations through visual inspection, data collection forms, photographing specific corrosion areas, and recording well tender conversations. Additional reviews included wellhead repair procedures, equipment storage areas, and general shop refurbishing of used equipment.

Summarize Results of Field Review

It was significant, but not unexpected, that corrosion was observed at every location, however, the presence of corrosion was generally not an indication of immanent mechanical failure.

The following discusses the use of the data collection forms, obstacles to inspection, the effect of acquisitions, the effects on equipment pulled from service, the importance of coating at the time of initial installation or replacement, the effect of containment dikes, and details on specific areas of corrosion, including the various environmental and operating conditions affecting corrosion.

The original data collection form proved too burdensome and complicated during the first inspection to complete while inspecting the well site, selecting areas to photograph, and traveling between locations in a pick up truck or four-wheeler. Therefore, in order to maximize the number of locations reviewed, further reviews utilized spreadsheets of wells and associated equipment by welltender route, accompanied by brief field notations and photographs. Stripper well operators would find this methodology more effective for completing field reviews, making specific notations regarding painting,, repair, or replacement.

Obstacles to visual inspection included well access, recent painting, and weeds. When well access was impossible due to road conditions, only the associated tank batteries near the main road were reviewed. Where recently painted surfaces made corrosion inspection difficult, the painting results were then reviewed. Weeds and un-mowed areas obstructed visual inspection especially around wellheads or bottoms of tanks. Field reviews should be coordinated to coincide with site maintenance. that is, after mowing and before painting.

It is important to note that most of the wells reviewed were the result of various acquisitions and it was evident that the previous maintenance affected the current condition of many of the wells. Previous operators could be identified based upon the current condition of the facility.

The field review and prior experience identified that corrosion is accelerated when equipment is pulled from service and left open to the atmosphere where oxygen is plentiful. Therefore, equipment should be returned to service quickly or left in service until needed. Tubing or casing pulled from service should be kept on storage racks and have all thread ends cleaned and lubricated for corrosion protection.

It was determined as a result of the field review that the best time to provide equipment with the most effective corrosion protection is upon initial installation or replacement. This typically involves a good coating of paint for most surfaces and coal tar for tank bottoms. A good primer and enamel topcoat will provide many years of effective protection and should be applied soon after installation. Care should be taken during installation not to scrape the protective coating from hard to access areas. Touch up painting should be completed prior to final hook up with any bright metal marks from pipe wrenches or field cut threads temporarily coated with spray paint to minimize the effects of corrosion.

The following discussion focuses specifically on field review results regarding wellheads, casing, tubing, separators, tanks, and pipelines.

Wellheads, Casing, and Tubing

The field review identified that wellheads experience corrosion in valves, connections, and in the top joints of the casing and tubing. Surface corrosion appeared due to improper maintenance, leaking connections, and partially covered wellheads. Downhole casing problems were mainly related to H_2S and coal bearing zones caused by insufficient primary cementing.

Corrosion was evidenced on the top joints of the production casing and tubing near the packing due to wellhead designs that leave a bowl for water to collect. Lack of protective coating further provides a corrosive atmosphere enhanced by produced brine chlorides from leaking connections. Pipe wrench marks and field cut threads were observed to leave areas of bright metal exposed for corrosion to occur.

Wells on pump that produce oil benefit from the corrosion protection afforded by leaking stuffing boxes. The small amount of oil and paraffin that gets by the stuffing box provides an effective barrier to moisture and therefore corrosion. While a leaking stuffing box is not a recommended practice, the result is a coated and protected wellhead.

Portions of some wellheads were partially covered with soil due to location regrading, thereby masking any possible corrosion in valves or connections set below ground level. Even when not buried below ground level, corrosion frozen valves are difficult and dangerous to open or remove. All valves should be lubricated and operated at periodic intervals to minimize the potential for a freezing up due to corrosion. Finally, any exposed threaded outlets should be coated to prevent corrosion of threads and preserve their usefulness.

Experience indicates that downhole casing leaks are caused by H2S or coal bearing zones on the outside of the production casing. Mechanical failures are accompanied by decreased gas production, increased fluid production, discolored or muddy water, an H_2S odor, and decreased wellhead pressures. Instead of exact casing leak location identification, stripper well operators can generally remediate by setting a packer into the cemented portion of the well, then utilizing chemical inhibitor to mitigate any additional damage. Some wells may require a second string of tubing or the addition of slim hole rods and a pumping unit to maintain effective fluid removal.

H_2S can be due to formations that produce H_2S or the occurrence of sulfide reducing bacteria, or SRB's. H_2S bearing formations are generally area specific and can be delineated by most operators. Primary cementing over these intervals can prevent future costly corrosion remediation. SRB's reduce sulfates in oilfield waters to form H_2S. H_2S reacts with iron in tubulars to form iron sulfide, causing failures and leaks in flow lines, valves and process equipment. Treatment of the un-cemented section of the production casing and SRB's can be controlled through chemical inhibition. The known corrosiveness, toxicity, flammability of H_2S make it hazardous to well tenders and adjacent landowners. Therefore, stripper well operators should identify all facilities with H_2S , and then assess the potential health hazards.

Decision trees and procedures for the maintenance and repair of wellheads, casing, and tubing were documented and incorporated into the procedure guide.

Separators and Production Units

Field review identified that most separators and production units reviewed were in fair condition with the exception of those affected by leaking connections or missing control covers. Leaking connections typically involved produced brine rather than oil causing additional corrosion damage. Regulators and fluid level control unit corrosion seemed associated with missing or improperly closed covers. Regular painting, eliminating leak, and restoring covers to separator controls should effectively mitigate most occurrences of corrosion. Production units or separators pulled from previous service, due generally to abandonment, will benefit from shop restoration rather than field repair prior to returning to service.

Production Storage Tanks

The field review provided for a review of the extent of corrosion, the storage vessels utilized, the areas of corrosion, mechanical failure identification, the effects of dike construction and tank setting, general operating practices, a used tank storage area, and summer painting crews.

Corrosion was evidenced on every steel tank reviewed with affected areas including external surfaces, tank ladders, heater tubes, behind labels, and tank inlets and outlets. Tanks reviewed varied from cement, plastic and steel composition, and from 25 to 210 barrel. Although a number of in-ground cement vaults were reviewed, few were being utilized due to cracks. The condition of the steel tanks varied from excellent to those that had been completely corroded. Steel storage tanks have a significant tendency to corrode due to the varying fluid levels and fluid types contained, with significant internal corrosion when only brine is present. Most tanks were experiencing localized exterior corrosion with pitting occurring and appeared due mainly to improper maintenance and leaking connections.

Well tenders reported that most mechanical failures are identified by visible seepage, although static or decreasing tank fluid levels with normal gas production and operating pressures were also indicative of a hole in the bottom of the tank. Leaking tanks are drained, pulled from service, and taken to a storage area where a number of tanks can be efficiently repaired at the same time. Tank replacement decision trees and repair procedures are included in the procedure guide.

Improper tank setting in containment dikes can often promote premature failure due to the moist environment associated with dikes. Tanks should be set slightly elevated from the remainder of the dike and the dikes drained regularly. Tanks were observed to be set on gravel, clay, and railroad ties. Some other operators also reported tanks set on cement. Since visual inspection of the bottom external surface of a steel tank is impossible, it is important for operators to properly coat the bottom of a tank with mastic and then set the tank without affecting the coating. The remainder of the tank exterior can then be regularly painted to maintain corrosion protection. A review of tanks returned to the equipment yard for repair generally revealed a few areas of pitting rather than uniform bottom corrosion.

Additional corrosion was observed behind tank labels where the top of labels had parted from the tank allowing water to collect. Well tenders should replace loose labels, while annual maintenance should remove damaged labels prior to repainting. It was also observed that some heater tubes on tanks were noted to be welded shut due to leaking associated with extended use.

Tank ladders can be a significant safety issue for well tenders when proper maintenance is ignored and ladders allowed to deteriorate. Repainting ladders is not easy, so oftentimes maintenance crews do not properly clean or paint corrosion troubled areas.

One beneficial field practice identified was introducing two to three barrels of crude into steel tanks where only salt water was produced to provide a coating to oxygen. One detrimental practice was draining small quantities of salt water into the diked area while transferring saltwater to observe when oil had been reached. The cumulative effect of drainage and leaking valves further aggravates the already corrosive environment at the bottom of tanks.

Well tenders reported that load lines experience internal corrosion at tank inlets where saltwater continually lays at the bottom of the line. An un-repaired leak in this area can then initiate corrosion on the exterior of the tank.

A review of the painting practices of two summer crews revealed that surface preparation of tanks and separators could stand some improvement, however, paint or primer were generally applied to most surfaces. Surface preparation was generally limited to a wire bush and scraper. Hard to access areas generally did not receive a lot of attention, either in surface preparation or painting. Previously painted areas that were not properly prepared had blistered and will require re-treatment. Some operators report utilizing high pressure washers or air tools for some maintenance.

Plastic tanks are used for initial installation or replacement of steel saltwater storage tanks. Oilfield supply companies and operating company inquiries confirmed the predominant usage of plastic tanks for saltwater storage. Plastic tanks are superior to steel and fiberglass tanks in cost, impact resistance, and availability. Plastic tanks have also proved superior to in-ground cement vaults due to the cracking associated with cement vaults. There has been general good success utilizing plastic tanks, although some improperly installed tanks experience failure at the tank inlet, possibly due to repeated surges while attempting to remove wellbore fluids. Most plastic tanks reviewed were coated with paint to reduce the degrading effects of ultraviolet rays.

Pipelines

No pipelines were visually reviewed during the field review process, however, some areas of previous replacements were reviewed and one example of stray voltage corrosion was also investigated.

The following discusses general stripper well operation, obstacles to leak identification, pipeline monitoring methods, pipeline repair methods, the use of plastic, and hot spot protection.

Experience indicates that pipelines represent a significant investment for most stripper well operators with pipeline corrosion resulting in a loss of mechanical integrity and an associated loss of product. As previously discussed, stripper well gas gathering systems are often a conglomeration of acquisitions resulting in systems comprised of various materials, diameters, and ages, but generally neither coated nor cathodically protected. Unless problems arise as leaks or pressure restrictions, existing lines are utilized and not inspected until dug up for system changes, repair, or replacement.

Major obstacles to leak identification and overall system understanding include inadequate maps, unidentified lines, poor pipeline right of way maintenance, and well tender responsibility for large numbers of wells over wide geographic areas. Well tenders are often responsible for leak identification in addition to their other duties.

Pipeline mechanical integrity is monitored daily by well tenders through production and pressure monitoring of check and master gas sales meters. Production managers further identify line loss by monthly or weekly production variance reports. Electronic metering was observed to provide regular monitoring of remote sites for comparison to weekly individual well chart integrations. Well tenders are constantly on the lookout for the physical signs of gas leaking during normal operations.

Pipeline corrosion is addressed first by repair if possible, then by replacement when necessary. Repairs are often completed by roustabout crews using a shovel and a clamp where possible. It is not unusual to have “several” clamps on small sections of line. Stripper well operators sometimes struggle with the economics of line repair over replacement.

When line replacement is necessary, plastic is utilized wherever possible and practical. Plastic pipe is often used for initial installations, replacement of existing steel sections, or as a slip liner within existing steel lines. The use of plastic either as a complete replacement or as a slip liner inside existing pipelines is recommended where operating pressures are appropriate.

The apparent phenomena of successive leaks in steel lines once initial repairs are made or the accelerated corrosion of replacement sections is explained as follows. The surrounding top soil is oxygenated (made cathodic) when it is dug up creating increased potential for corrosion compared to soil beneath the line. Similarly, new steel pipe experiences accelerated corrosion compared to the previously corroded steel. Hot spot corrosion protection utilizing sacrificial anodes may be an effective method of preventing future corrosion in these two circumstances.

Decision trees are provided in the procedure guide to assist stripper well operators in managing the effects of pipeline corrosion.

Decision Tree Development

Decision trees were developed for the common areas that are affected by corrosion problems in stripper wells, then to select the most appropriate corrosion mitigation method. One decision tree provides a general methodology for stripper well operators to develop a plan for addressing the overall problem of corrosion, while additional decision trees are provided on specific areas of corrosion including downhole casing, wellheads (casing and tubing), production tanks, and production and pipeline leaks. The decision trees utilizes database and field gathered data to assist the operator in selecting the proper corrosion mitigation methods.

General Methodology

The general methodology decision tree, Figure 1, provides a four-phase process to systematically assess corrosion problems associated with stripper wells. The form provides a methodology to evaluate the application of corrosion mitigation methods for stripper gas wells by focusing on the most common areas of corrosion. The form is divided into four sections, Phase 1 – Identify the Problem, Phase 2 – Measure the Problem, and Phase 3 – Solve the Problem, Phase 4 – Monitor the Problem.

Phase 1, Identify the Problem, prepares a database of information to review potential areas of corrosion based upon field review, wellbore schematics, map preparation, and leak repair summaries.

Phase 2, Measure the Problem, determines the priority through review, additional decision trees, cost estimates and preliminary economics. Stripper well operators should be aware that protect fifty percent of wells and associated systems will result in protecting probably ninety percent of total value.

Phase 3, Solve the Problem, confirms the expense justification based upon payout, npv or other method. Decisions are then made to complete the proposed work or rather to sell or plug and abandon. Based upon an annual budget estimate, schedules are then prepared for maintenance, repairs, or replacements.

Phase 4, Monitor the Changes, monitors the effects of corrosion through gas sales variance reports, weekly well tender meetings, annual facility reviews and pipeline inspections, documenting maintenance and repairs, and reviewing pipeline repairs to identify trouble areas. It is critical to monitor the corrosion mitigation methods employed compared to the results desired to continuously improve the process.

Specific Decision Trees

Study results indicate that common areas of corrosion include un-cemented H_2S or coal bearing zones, top joints of tubing or casing, unprotected wellheads, leaking connections, steel salt water tanks, heater tube areas, bottom of steel storage tanks, and bare steel pipelines in corrosive environments.

Stripper well operators are directed to the use of the specific decision trees in Phase II of the general decision tree including casing, tubing, wellheads, separators, tanks, and pipelines.

Decision Tree Test Analysis Results

The decision trees are based upon commonly available information, process identification, and steps to alert the stripper well operator to the identification and mitigation of common corrosion areas. Continued analysis of the methodologies are currently in progress. The results of the decision tree testing will be provided in the final report to the Stripper Well Consortium.

Procedure Guide Preparation

Based upon the research performed in this study, a procedure guide was prepared that details the utilization of the Data Collection Forms, and the Decision Trees.

The procedure guide provides a detailed description of the corrosion process, corrosion identification and mitigation guidelines, potential failure paths, and diagnostic tool designation are also provided. Diagnostic tools include wellbore schematics, weekly well tender reports, gas sales variance reports, swab reports, gas sales charts, gas leak detectors, portable gas analyzers, gas line detectors, and soil analyzers.

Additional sections are provided in the procedure guide appendix on surface preparation and painting guidelines, and plastic pipe usage guidelines. Definitions, abbreviations, and lists of manufacturers, suppliers and information sources are also provided including complete addresses, phone numbers, and website addresses.

The methodologies developed as result of this research will be presented at Petroleum Technology Transfer Council (PTTC) meetings and provided to the Department of Energy to include as a resource on their web site.

The goal of the procedure guide is to assist operators in economically evaluating and identifying the appropriate corrosion mitigation methods for stripper well operators based upon commonly available data.

Should any additional information be required, all subjects previously discussed are amplified within the text of the final report presented to the Stripper Well Consortium under the Subcontract Number 2283-JE-DOE-1025, as sponsored by the Department of Energy.

Conclusions

Corrosion affects every stripper well to some degree and if left unchecked results in the repair or replacement of casing, rods, tubing, separators, production tanks, and pipelines. Additional effects include lost or deferred production, lower equipment salvage values, environmental damage and associated penalties, and decreased safety.

The costs associated with corrosion, while substantial can be managed best when considered as a cost of doing business. Proper planning should significantly reduce the amount of time and expense that would otherwise be required for addressing corrosion related issues.

Stripper well operators face multiple challenges, cannot afford to utilize the same corrosion control methods as major transmission and natural gas storage companies, but still require economic, efficient, easy to use techniques for corrosion mitigation.

Stripper well operators should develop in-house expertise through education, and training through the West Virginia University Appalachian Underground Corrosion Short Course. It is important that stripper well operators employ consistent methodologies that includes an equipment database, cost estimates, economic prioritization, an annual budget, scheduled maintenance, documentation, and monitoring when planning to effectively mitigate the effects of corrosion.

While the process of corrosion is complex and often misunderstood, it is largely controllable. Primary cementing of production casing over H_2S or coal bearing zones or chemical inhibition should eliminate most downhole casing problems. Regular maintenance through surface preparation, painting, and leak correction would eliminate many wellhead and tank related problems. Proper tank setting and bottom coating would significantly reduce most tank bottom corrosion related incidents. Utilizing plastic tanks for salt water storage would eliminate most of the problems associated with steel tanks. Finally, coated pipe, cathodic protection, hot spot protection, and the use of plastic for pipeline replacement would significantly reduce many pipeline corrosion problems.

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Figure 1
Decision Tree Form For Corrosion Mitigation

Phase I: Identify the Problem
1. Complete field review form by well tender
2. Prepare well equipment inventory
3. Prepare wellbore schematics for problem wells
4. Prepare map identifying wells and pipelines
5. Estimate average production per well, mcfdeq
6. Prepare gas sales variance report
7. Prepare leak, repair, or replacement summaries

Phase II: Measure the Problem
1. Sort wells by gathering system then by descending mcfdeq
2. Determine system priority by mcfdeq, variance, and environmental concerns
3. Review maps, schematics, and leak summaries
4. Utilize appropriate equipment decision tree form
5. Estimate costs for maintenance, repair, or replacement
6. Prepare economics by well and gas system

Phase III: Solve the Problem
1. Confirm expense justification: payout, npv
2. Complete work, sell, or plug and abandon
3. Estimate annual budget for expenditures
4. Prepare repair schedule
5. Prepare maintenance schedule
6. Prepare replacement schedule

Phase IV: Monitor the Changes
1. Prepare monthly gas sales variance reports
2. Conduct weekly well tender meetings
3. Complete annual review of all facilities
4. Complete annual pipeline inspection
5. Document maintenance and repairs
6. Review pipeline repairs to identify trouble areas

Endnotes

[i] H.J. Endean, "Oil Field Corrosion Detection and Control Handbook", Champion Technologies, 1989

[ii] SPE Paper 72359 "Low Cost Methodologies to Analyze and Correct Abnormal Production Decline in Stripper Gas Wells" by Jerry James, Gene Huck, and Tim Knobloch, James Engineering, Inc., SPE-AIME

[iii] "Corrosion Costs and Preventive Strategies in the United States" Report FHWA-RD-01-156

[iv] J.T. Kabay, "Corrosion Control Considerations for M&R Stations", TW Phillips, Appalachian Gas Measurement Short Course , 1977

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APPENDIX E:

2003 PROJECT FINAL REPORTS

TITLE PAGE

Report Title:
Design, Construct, Install and Test G.O.A.L. PetroPumps in 1 Oil and 6 Gas wells

Type of Report:
Final Report

Reporting Period:
July 1, 2003 – December 31, 2004

Principal Author:
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DOE Award Number:
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Submitting Organization Name and Address:
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DISCLAIMER

Abstract

A 'Gas Operated Automated Lift Pump' G.O.A.L. PetroPump has been conceptually developed constructed in prototype and beta type tools, field tested and found to be applicable for use in removing fluids from "stripper wells" thereby increasing production of natural gas. Per the agreement with the Stripper Well Consortium '7' wells have been tested with the tool. Test results have shown a 1.5X to 4.0+ X increase in gas yields from wells tested. Bench scale and laboratory test of the key tool component, the automated pressure controlled valve assembly, has established the potential applicability of a prototype tool/ beta tool [field ready] in watered out stripper wells. Tool applicability is targeted to operating conditions of 50 to 600+ psi down hole pressure with brine and fluid lift capacity varying from 0.1 to 9.0+ BBL/ tool cycle. In field precursor testing of a pilot predecessor tool of larger dimensions and weight than that targeted for fabrication and deployment as part of this SWC 7 well program had shown promising results. The precursor field test of tool [s] have shown improved natural gas production 1.6 X to 2.4X, regular automatic cycling of tool [1 Trip each 1 –1.5 Day] and auto lifting of brines [0.33 – 1.5Bbl/cycle] from a brine producing natural gas stripper well. Field testing of the above referenced designed prototype tool for this phase of the project showed similar brine production [0.25 to 1 Bbl/ tool run with 1 to 2 day cycles] and frequency of tool cycles during the early period of field trials. Field trials of the prototype [smaller body and length] tool evidenced metallurgy problems in materials construction compatibility resulting in premature actuator failure and decreasing frequency of tool runs and lesser quantity of fluids production with each subsequent tool trip. Field and laboratory analysis diagnosed the problem and designed a remedy for further in field-testing. This premature failure was diagnosed as corrosion on one of the actuator components. The problem occurred as a function of miniaturizing of components to achieve a desired, "well tender friendly" smaller tool configuration. Additional lab trials and in field testing of the smaller beta type tool [field ready] with a modified more corrosive resistant actuator took place in the 4th calendar quarter of 2002 through 2004 and were successful. Additional tool modifications were made through out the 2002-2004 test period which resulted in more efficient tool to casing seal cups, ` 50% miniaturization of tool and components affording size/ weight reduction of the technology and potential application for a broader application in more wells of 3.0", 4.0" and 5.0" diameter. This work was conducted by BEDCO as part of its on going commitment to establish working G.O.A.L. Tool technology to assist in the production of gas and oil from the nations aging stripper wells. This work was supported by the SWC and NYSERDA in a follow on award for field trials of 7 G.O.A.L. PetroPump Tools.

The cost of the G.O.A.L. PetroPump and the attendant well head modifications in comparison to the 1.5X to 4.0X + improvements of gas production achieved by the beta-type [field ready] tools, at current market prices of $5.00+ Mcf, indicate a potential payback on capital investment of less than 1 year.

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INTRODUCTION

The following is the final report under DOE NETL Prime Award No. DE-FC26-00NT41025, Subcontract No.2052-BEDC-DOE-1025 V-3 on the development of a prototype tool and beta type tool for the automatic lifting of brines with subsequent improved gas flow production from watered out stripper wells. This feat is accomplished through the use of an on tool automated pressure-sensing/ actuating value that is preset to pass through a predetermined volume of brine with subsequent lifting of that brine to a surface process unit and brine tank. The energy for that lift is powered solely by in well geologic formation pressure.

EXECUTIVE SUMMARY

More than 8% of the US natural gas production is derived from “Stripper Wells” [A stripper well by definition is < 50 MCFD] currently averaging approximately 15-mcf/ day or ~ 1.5 TCF/ year. Much of the United States and the world’s natural gas producing wells suffer from declining and restricted production due to the presence and build up of brines in the well bore. Stripper oil wells in the lower 48 states supply 15% of domestic oil consumption. Total numbers of stripper oil and gas wells was quantified in 2003 as~ 650,000. In total ~ 18,000 oil and gas striper wells were abandoned in 2003 with a lost oil and gas value in excess of $530,000,000. Over the past 12 years the lost value of abandoned/ plugged wells is equal to $6.5 Billion dollars and a projected 35,000 associated job losses, according to the IOGCC 2004. This loss and abandonment is in part related to the fact that conventional techniques for addressing and or removal of the brine and total fluids are cumbersome and costly. The scope of this project was to develop an alternative technology [total fluids pump] for the automatic lifting of that brine/ fluid to the surface using in well down hole pressure to activate an in tool valve. This sensing control valve is automatically held open by an internal pressure sensing mechanism allowing the tool to drop into the fluid column in the well. Passage ways through the tool allow passage and accumulation of brine/ fluids atop the tool to a preset column thickness at which time the on tool pressure sensing mechanism closes the tool valve. This closure is accomplished via the combined hydrostatic pressure of the brine atop the tool and system backpressure. An in well down hole seal of the tool to the casing is accomplished by a set of dual flex cups which surround the tool and make circular contact [seal] with the well casing. Subsequently tool and fluid column are lifted to the surface driven by below tool formation pressure [in well below tool pressure].

In the work completed to date on this project BEDCO has confirmed the need for and applicability of an automated tool, which will remove, accumulated fluids [brines] from gas wells and increase gas flow. BEDCO has confirmed these needs and results of increased gas yield post brine removal from wells via meetings, work sessions, well records review, interviews with well field owners and operators and preliminary production response from predecessor tools. These owners and operators currently use sundry methods of brine removal to produce gas from their stripper wells. Interviews with both well owners and operators speak to a common problem in production of natural gas from stripper wells using conventionally available techniques. That problem being, that current production techniques and tools for removal of fluids [Brines, condensate and oil] leads to intermittent and often irregular production of gas from stripper wells and certain process unit problems such as winter icing. A need for regular automated fluid removal and more uniform gas production is desired and needed.

BEDCO has produced and bench tested a prototype and beta type tools to meet industry needs and simulated in field testing with a 98% adherence/ correlation to the designed tool plan. The GOAL Pump Beta tool in field testing of 7+ wells has produced ever increasing reliability of the tool and tool system, achieving 1.5X to 4.0 X improved gas production.

BEDCO has further defined the numbers and types of wells applicable for such an automated tool through technical work and review sessions evaluating tens to hundreds of “stripper wells’ production records with a regional natural gas producers and meetings with State ad Regional organizations who maintain Stripper Well records. The number of wells for which the technology is applicable in the Appalachian Region alone, in the tools current configuration [i.e. sized for 4 inch ID wells], are numbered in the high thousands. Application through out the country coupled with further miniaturization of certain tool components, indicates wells for which the technology is applicable number into the tens of thousands perhaps 100,000 or more.

The completed work on bench tools, prototype and beta type tools for field use has focused on tool design and construction of durable materials that are tolerant of down well physical and chemical conditions. To that end materials of construction are Hastelloy, 316 stainless steel for all tool body parts and condensate tolerant synthetics materials for tool sealing cups and automated valve seats. Tooling and machining of components, assembly processes for components and current generation production prototypes are so configured to match with or lend themselves to standard oil and gas field specifications and conditions of service tool [s] availability and technician capability. A field demonstration beta type tool of 32” in length and 42# of total weight has been manufactured and was bench and field tested in more than 7 wells to determine performance characteristics and simulate as well as characterize in well/ in field-testing. Installation for this new beta tool design was first deployed in a chosen Lenape Resources Inc. natural gas well, LRI # 52. This occurred in March 2002. The well physical characteristics are show in Table 1 - 1 in the Appendix. Since that time of initial testing, the beta tool has been deployed in 11 wells.

It has been determined from predecessor [larger] tool testing that variable tool response is necessary to optimize the performance to low pressure wells [< 100 psi] and low volume fluid production [< 2 bbls/ day] from certain stripper wells. To address such needs BEDCO developed bench test apparatus for mock up tool configurations to simulate and address the need for variable stroke and valve seat configuration design to address variable well conditions related to geology conditions and life cycle of the well. Further this apparatus has been and is used to calibrate assembled tools for in field-testing and post field testing wear analysis. As noted previous, in field tool testing with prior generation pilot tools has confirmed this need and ability to adjust the tool to wells with lower down hole to well head pressure differentials and small [~1/3 bbl or less] brine [fluids] loads. It is also apparent from this testing that smaller [miniaturized] pressure sensor control mechanisms would allow for construction of a smaller tool and accommodate a wider selection of candidate wells and tool configurations. Producers express interest for a 2” to 2.5” diameter tool. Current evaluation of available materials and gas fluid lift ratio suggest a 3.0” OD tool could be developed and successfully deployed with some evolution of the technology and materials for in well/ down hole use.

Development of real time metrics which will quantify the results of the tool deployment and in well testing as well as provide detailed information for refinement of construction and operation of the tool were critical to the project success. We have determined that the oil and gas industry has begun to address these needs with a limited number of first generation continuous data loggers targeted to collect some of the key pressure and flow data associated with operating wells. BEDCO has further ‘in field” deployed and initiated configuration of such data logger units on a test well [s] to confirm its use and applicability to the “Prototype Tool and Beta Type tools”.

EXPERIMENTAL

SIMULATION AND ANALYSIS

Analytic modeling was developed to assess candidate fluid lift pump configurations. Analytic simulations indicated that the pressure at which a sensor controlled valve will close is controlled, to a first order, by the sensor-actuator compression ratio, spring force plus valve and shaft weight, and the initial sensor-actuator charge pressure and charge temperature. Additionally it was concluded analytically, that the pressure at which a sensor-actuator controlled valve will open, once closed, is related, to a first order, only to the ratio of the sensor-actuator cross-sectional area to the valve cross-sectional area, the pressure above the valve, and the pressure below the valve. Based on these understandings, various valve and sensor-actuator geometry were analyzed and alternative configurations and operating strategies were evaluated.

DEVELOPMENT TESTING

A development test program was designed to correlate the analytic modeling and to provide calibrations for development of fluid lift pumps.

The test vehicle consisted of a tubular section containing, and supporting, a sensor-actuator assembly. This was attached to a cylindrical valve seat assemble. A valve shaft was attached to the lower [free] end of the sensor-actuator in such a way that as gas pressure [forces] compressed the sensor-actuator the valve head was pulled up into the valve seat. Upper and lower pressure caps were attached to the cylindrical assembly. Bottled nitrogen plus control valves and gauges completed the test set up. Testing was also conducted with test items immersed at pressure under water. The results indicate no significant difference between water and air [gas] testing.

Tests were initiated with the sensor-actuator-controlled valve in the open position. Gas pressure was increased below the valve, filling and pressurizing the total test vehicle, until the sensor-actuator assembly compressed closing the valve. This simulated the fluid pump descending into the well, being exposed to the flow pressure and hydrostatic fluid pressure, and eventually shutting in the well. The testing established the validity of the analytic modeling of in-well valve closing providing an analytic basis for design modifications.

Each test was continued to simulate the fluid pump arriving at the well head. The pressure above the sensor-actuator-controlled valve was bled off; corresponding to that which would be dissipated into the tank and sales line as the fluid pump approached the surface. The pressure above the sensor-actuator, in the test vehicle, was varied parametrically from one to five atmospheres to assess the validity of the analytical modeling. The pressure below the valve, and sensor-actuator, was reduced until the valve opened. This represented the reduction of well flow pressure that would result as the gas was discharged from below the liquid pump. Once again, the experimental data was in good agreement with analytic predictions of the conditions necessary for valve opening. Analytic modeling was used to evaluate alternative fluid pump designs and operating strategies.

FLUID PUMP CONFIGURATIONS

Two sensor-actuator diameters and several valve head configurations were tested over a range of simulated operating conditions. A liquid pump design was tentatively selected, fabricated and tested. Sensor-actuator compression ratios were varied (stroke adjustments) and sensor-actuator charge pressures were selected parametrically to characterize the liquid pump development model. Figure 1 represents sample results of development testing for the selected configuration (hundreds of test have been conducted with a variety of configurations).

Table 1 Gas Operated Automatic Liquid Pumping System (fluid pump)

Bench testing of TOOL #1 with a reduced stroke. **August 10, 2001**

Summary: Calibration testing of Tool #1 was conducted with a reduced stroke of about 1.05"

Test Results: (Pressure are PSIG) **Stroke about 1.05 inches (+\- .02")**

Charge Pressure	Valve Closing Pressure	Pressure above Valve At Valve Opening	Opening Pressure	Absolute Pressures Calculations Pcharge	Pclose	Popen	Po/Pc	Pa/Pc
20	58	20	32	34.70	72.70	46.70	0.64	0.48
20	58	0	20	34.70	72.70	34.70	0.48	0.20
20	55	0	18	34.70	69.70	32.70	0.47	0.21
20	56	0	18	34.70	70.70	32.70	0.46	0.21
20	55	30	40	34.70	69.70	54.70	0.78	0.64
20	55	30	40	34.70	69.70	54.70	0.78	0.64
20	57	20	32	34.70	71.70	46.70	0.65	0.48
30	70	30	43	44.70	84.70	57.70	0.68	0.53
30	70	30	44	44.70	84.70	58.70	0.69	0.53
30	73	30	44	44.70	87.70	58.70	0.67	0.51
30	70	50	59	44.70	84.70	73.70	0.87	0.76
30	70	60	65	44.70	84.70	79.70	0.94	0.88
50	106	50	66	64.70	120.70	80.70	0.67	0.54
50	107	30	51	64.70	121.70	65.70	0.54	0.37
50	107	20	42	64.70	121.70	56.70	0.47	0.29

In all testing, the calculated absolute pressure ratios (that is, valve opening pressure/valve closing pressure, and pressure above the valve at opening/valve closing pressure) can be characterized by a straight line plot, the slope being determined by the ratio of the sensor-actuator effective cross-sectional area to the valve seating cross-sectional area.

Specifications have been developed for the fabrication of two alternative sensor-actuator configurations; one with a reduced diameter (1.70” vs. 2”), and both with longer available strokes (20% increase). Discussions are in process with suppliers.

RESULTS AND DISCUSSIONS

The project has been broken down into six major tasks. Those work tasks and the status of activities on those tasks are outlined below:

1.0 COMPLETE DESIGN OF PROTOTYPE TOOL

1.1 The project senior engineering, senior manufacturing and scientific personnel have conducted meetings and work sessions with field engineering/ well operations personnel to outline field durability needs, assembly, adjustment, ease of installation and service specifications for the prototype tools. Findings indicated the obvious needs for chemical compatibility with down hole chemistry. This is addressed via the use of Hastelloy, 316 stainless steel - metallurgy and valve seat and sealing cup chemistry that will be tolerant of both brine and condensate. Additional findings go to near term application of the tool in 4 inch casing wells and longer term application of tool use in tubing of 3.0 inch and 5.0" cased wells. Immediate needs for the 4 inch cased wells addressed tool total weight, total length, and assembly/ deployment/disassembly of tool components in the field.

1.2 Specific elements that have been addressed are the length, weight and tool diameter to allow for maximum use in varying type of wells and minimum amount of reconfiguration of well head and associated cost. Ancestral tools were in excess of 5 to 6 feet in length and 70 to 105 pounds in weight. Operating BEDCO predecessor prototypes were 46 inches in length and weighed to ~54 pounds. The tool constructed and bench testing for deployment and testing for the SWC 2002- 2004 project [7-Beta Tools] is 32" in length and weighs ~ 42 pounds. This design and construction configuration allows ease of deployment of the G.O.A.L. PetroPump and retrieval by a well tender with minimal changes in configuration to a typical well head lubricator.

1.3 Another specific element determined in field meetings for tool modification is the component assembly characteristics. Field assembly, disassembly and adjustment must be possible with the fewest number of field tools and personnel to assist. To that end, tool design and construction has been simplified and addressed to oil and gas industry standards. This includes only three- [3] field serviceable disconnects and these are constructed with standard 6 pitch General Acme threads. Components have been reduced from 50 or more on ancestral tools to 27 or more [54" tool] in immediate predecessor tools to 14 for the 7 field tested Beta tools. Basic material for the tool body is commercially available Hastelloy [TM] and durable 316 stainless steel. Minimum steps for tool assembly and large milled tool flat areas [wrench flats] complete the simplified design and assembly. This design/ construction/ assembly approach all lends itself to service and maintenance work by standard industry tools [i.e. 36" and 48" pipe wrench, 18" and 24" adjustable wrench and 3# and 5# hammer].

1.4 Field and bench testing has lead to further tool modification of valve seal mechanism [fixed alignment of valve seats], actuator durability and miniaturization, new compounding and configuration of seal cups improving simulated and field confirmed results with the SWC new designed and field tested tools.

1.5 Project senior engineering, manufacturing and scientific personnel have conducted work sessions and have completed prototype and beta type tools in conjunction with the specialized machining firm of Eagle Tool and Die. The tools completed bench testing and well simulation testing. The, "user friendly", smaller tool was installed in a test well[s] in March 2002 through end of 2004. To achieve the above referenced reduced size and weight of tool, senior engineering designed for the use of a new design and constructed [20 % smaller diameter] self actuating control mechanism for

the automated control valve. This major change in design and construction fostered other reductions and size leading to the decreased tool length of ~15" from predecessor tools @ 54" to the current 32" prototype/ beta type tools for SWC in well demonstration and decrease in weight of ~12 pounds to a current weight of ~42 pounds. These represent significant changes, which lend them self to one-man installation and ease of use and retrieval. Tool drawings and list of materials stock for machining of components and assembly have been simplified in form and reduced in total numbers of components to 14 from 27. The drawings and materials stock list are completed. The documents have been reviewed by the joint team to determine the possibility of further simplification and reduction in component parts. Valve actuator corrosion protection and protection against over-pressurization from ambient forces down well was determined as factors in tool operations and design/ construction compensated.

1.6 Project senior engineering in conjunction with the manufacturing director have designed, constructed, modified and refined a bench testing device on which the prototype and beta type tools have and were tested prior to and post in field testing. Lab testing of varying pressure [equating to differing in well brine head/ pressure] simulations has been tested to confirm viability and operational integrity of the constructed bench testing equipment and tool critical components. Changes in the actuator stroke and seating area of the self actuating valve assemble have been subject to test to allow for and confirm potential for operation in low pressure and small brine volume/ fluid load environments.

1.7 Specifications and modifications to the pressure sensing [valve control] device for the operation of the in tool automatic valve have been developed from the above completed meetings, work sessions and test stand work with specific reference to targeted installation wells.

2.0 CONSTRUCT AND BENCH TEST PROTOTYPE/ BETA TYPE TOOLS

2.1 The prototype and beta type tools were constructed and bench tested against design parameters to which it adhered with greater than 98% correlation. The tools were "in lab modified" to accommodate learned information from predecessor and on going field test to avert over pressurization by ambient forces in down hole conditions. Well operation simulation testing is on going as part of company QA/QC and product evolution on tools retrieves post field testing.

3.0 SELECT CANDIDATE WELLS

3.1 Meetings and work sessions with Lenape Resources Inc. Seneca Resources, Cotton Well Drilling, Chatham Resources and RMOTC and others have been conducted to assemble a list of candidate wells and choose wells for testing of the "Prototype Tool" and Beta Type tools.

3.2 Starting with a list of more than 300 operating and shut in stripper wells a short list of more than 50 wells was assembled. This short list was further refined to ~ 12-15 target wells. From those alternative wells, LRI # 52 and # 29 were chosen for initial Prototype/ beta type tool testing with many of the other wells referenced above chosen for Beta type tool testing.

3.3 Considerations evaluated in choosing LRI # 52 and LRI 29 include total yield over time since completion, current yield, and history of fluid production, decline curves and previous testing database.

- **As noted above, two alternative test wells were initially considered. LRI # 52 and LRI #29 were subsequently both evaluated for initial field tool use and evaluation.**
- **Data on these wells is shown in the appendices**
- **LRI # 52 had been previously tested with predecessor [54" larger tool] tools, a standard casing swabs, small diameter tubing and has the most complete available history of technical data for evaluation and comparison of the many variables associated with gas production which makes it a technical favorite for testing and analysis. The well however is associated with a sales/ gathering system which periodically [especially during low commercial gas demand] that pressures up to in excess of 100 psi [~ equal to down hole pressure] versus normal operating pressures of 50 psi making gas production from the well under those conditions onerous to not possible.**
- **Well LRI # 29 as a candidate has less data base and history of close watched operations, but has an advantage of being produced into a sales line with an LRI owned/ operated compressor station which theoretically can minimize wide/ wild swings of back-pressure on the system to 40 psi or less.**

3.5 Associated data on water/ brine production on these wells and other back up candidate wells was and continues to be assembled along with well response [production] information related to intermittent or regular removal of those brines. The final choice of initial test well[s] was made upon data review and completion of tool assembly with in field-testing initiated in March of 2002 to current on well # 52 and shortly thereafter on well LRI- 29. The additional 9 wells tested were done so in 2003 and 2004 after further tool modification resultant from initial test on the LRI wells.

4.0 TEST WELL PRODUCTION

4.1 Quantification of gas production before, during and post "Prototype Tool' deployment is a key element on the development of metrics to confirm applicability and success of the tool. Current technology on most wells for quantification of gas yield and pressure is performed by analogue instrumentation. This analogue instrumentation is tied to a specific orifice plate size in the well process unit and recorded on a circular 'pie' chart. The charts are subsequently integrated and quantified by third party off site contractors at a later date.

4.2 The project scientist and engineers assembled some of this analogue data as it relates to the first target well for in field-testing and continue to assemble review and interpret this historic data. Production from this well meets targeted test parameters. Those parameters include down hole pressure and historic production challenges which between the period of 1994 to 1999 showing low to no gas production from this well # 52 prior to physical swabbing / brine removal with a work over rig to remove several tens of barrels of brine.

4.3 In field process production data from a larger BEDCO [54" tool] and even larger/ heavier predecessor tool also underwent analysis and was used in final fabrication of the SWC prototype test and beta type test tools and wellhead modification parameters. Reduced data to date from this predecessor tools shows an increase gas production from [2] two different stripper wells of >1.6X to 2.4X. Regular tool automatic cycles at 1 cycle each 1-1.5 days with 0.3 to 0.8 barrels of fluid produced per cycle @ 15 to 20 cycles/ month yielding 8 to 10 barrels/ month of brine are recorded. In well and at well head operating conditions evidence typical pressure

ranges expected for the SWC - 7 well test of 50 to 60 psi backpressure [sales line] and down hole pressure conditions of 100 to 150 psi.

4.4 Real time comprehensive data collection of well head, process unit and sales line pressure and flow are critical to thorough comprehension of well and tool operation. To that end BEDCO has acquired, modified and deployed a digital recording data logger[s] to capture this type of information. Digital data loggers can collect comprehensive "real time" data at the well head and the process unit. Technical information was first assembled on manufactures and suppliers of continuous recording digital data loggers [well head computers] to collect and log both volume yield and pressure through out the well head and process unit system.

4.5 Bids were solicited for the purchase of a unit most applicable to project needs.

4.6 A successful bidder/ supplier of the well head data logger was selected. The unit wellhead computer, solar panel and battery was purchased installed and field-tested.

4.7 The components of the unit have been field installed on a chosen data collection/ confirmation well in the Lenape Resources System. Unit software and sensors have been installed and calibrated. Results to date show accurate relative correlation with analogue recording charts [for delta P of < 20"] on the well and the ability to collect and recorded data in digital form on as frequent as 1-minute intervals. Down load of system data via cellular link has been proven viable. Soft ware challenges in manipulating the data for accurate/ absolute correlation/ comparison on a 1 to 1 basis were worked on by BEDCO and the equipment manufacturer to achieve in field data collection/ recording and telephonic down loading success.

4.8 Significant insight into post tool run production was gained from detailed analysis of the data logger results. The normal analogue charts system for well 52 and well 29 use orifice plates tied to an analogue chart which can record 20" of pressure differential which is recorded as an inked line on a pie chart. Volume of gas produced by the well is determined by integrating the area under the curve recorded on the chart. Off chart reading [>20"] are not recorded and cannot be quantified. Post GOAL tool lifts of fluid, the data logger recorded pressure differentials of 200- 300" for period of 15 minutes to 1 hour resulting in ***non quantified*** gas of ~ 0.5 to 1.5 M or more of gas / cycle of tool. This observation indicates that wells using standard analogue recording pie charts may not record several 10's of Mcf/ month for the well in which the tool is employed. For wells like LRI- 52 which makes 20-60 or more runs/ month this can equate to more than $1000/ year to several thousand in non quantified revenue at the well head. Down sales line master meter systems with larger scale metering units can capture and quantify this produced gas as part of a network of wells but not for the well tested. As such results achieved for well # 52 are bias low.

4.9 Preliminary field recorded data has been retrieved, downloaded and formatted for correlation with the analogue data from the well. An example of incremental data being recorded is presented in Figure 2. Daily summary data is also available.

Table 2

HOURLY REPORT
FLOW AUTOMATION CORP.
HOUSTON, TEXAS
DATE: 08/03/01

METER NAME: METER RUN #1 TIME: 05:20:33

CONFIGURATION DATA

Contract Hour	08:00	Spec. Gravity	0.6	Mole % CO2	0.0
Mole % N2	0.0	Energy Content	1000.0	Pipe Diameter	1.987
Orifice Bore	0.375	Tap Config.	Flange	Tap Location	Downstream
Temperature Base	60.0	Pressure Base	14.65	Atmos. Pressure	14.7
Low DP Cut-Off	0.5	Fpv Method	AGA8	Gross 2530 Method	2530-1992
Fwv Method	Manual	Fwv Factor	1.0	Water Content	1.0
Well Stream	Enabled	Well Stream Val.	1.0		

DATE	TIME	VOLUME MSCF	ENERGY MMBTU	AVG SQRT (DP * AP)	AVG. DP IN H20	AVG. P PSIG	AVG. T DEG. F
07/17/01	08:00	0.1699	0.1699	9.18453	1.31	51.6	1.89
07/17/01	08:30	0.1874	0.1874	9.71828	1.47	51.46	1.86
07/17/01	09:00	0.1871	0.1871	9.68400	1.46	51.3	1.84
07/17/01	09:30	0.1874	0.1874	9.68333	1.47	51.02	1.79
07/17/01	10:00	0.2043	0.2043	10.45441	1.73	50.06	1.62
07/17/01	10:30	0.1855	0.1855	9.60922	1.49	49.5	1.51
07/17/01	11:00	0.1714	0.1714	9.05914	1.32	49.46	1.5
07/17/01	11:30	0.1781	0.1781	9.23295	1.36	49.73	1.54
07/17/01	12:00	0.1902	0.1902	9.81453	1.53	50.06	1.59
07/17/01	12:30	0.1855	0.1855	9.48633	1.43	50.07	1.58
07/17/01	13:00	0.1693	0.1693	9.09532	1.32	50.15	1.6
07/17/01	13:30	0.1245	0.1245	8.77455	1.22	50.9	1.73
07/17/01	14:00	0.1014	0.1014	7.63768	0.87	53.57	2.2
07/17/01	14:30	0.2102	0.2102	10.66151	1.69	54.2	2.32

4.10 The "Data Logger" programming is being further addressed to provide more application to project needs.

4.11 Software and formatting components were reviewed and modified to meet project data needs. Additional considerations for future use include transducer outputs and event indicators (surface arrival and departure of the fluid pump) are being considered for incorporation in the status reports.

4.12 Data contained in Table # 3 was obtained via cellular down load connection with well #52 shows significant post tool run/ non quantified gas production readings referenced earlier in this report. Follow on tool run pressure and gas production increase significantly. Follow on pressure spiked at more than 300" of delta P and follow on gas production was >1 order of magnitude greater that normal production. The net results was produced gas that is not quantified by the standard analogue pie chart recording and accounting methodology employed on this and many wells. During just 1 period of 15 minutes noted on the chart below, the well produced > 1 mcf of gas which was not quantified on the analogue production [pie] chart. This well makes 20-60 tool runs/ month under variable line pressure conditions. This can equate to > $1,000 to $2,000, perhaps more/ year @ $5/ mcf in non well head quantified gas produced by this well with the aide of the GOAL Pump.

Table 3

HOURLY REPORT

FLOW AUTOMATION CORP.
HOUSTON, TEXAS

DATE: 02/17/03
TIME: 11:33:34

METER NAME: METER RUN #1

CONFIGURATION DATA

Contract Hour	08:00	Spec. Gravity	0.6	Mole % CO2	0.0
Mole % N2	0.0	Energy Content	1000.0	Pipe Diameter	2.0
Orifice Bore	0.375	Tap Config.	Flange	Tap Location	Upstream
Temperature Base	60.0	Pressure Base	14.65	Atmos. Pressure	14.7
Low DP Cut-Off	0.1	Fpv Method	AGA8 Gross	2530 Method	2530-1992
Fwv Method	Manual	Fwv Factor	1.0	Water Content	1.0
Well Stream	Enabled	Well Stream Val.	1.0		

DATE	TIME	VOLUME MSCF	ENERGY MMBTU	AVG SQRT (DP * AP)	AVG. DP IN H20	AVG. P PSIG	AVG. T DEG. F	
02/16/03	20:00	0.0105	0.0105	3.35824	0.18	45.22	60.0*	
02/16/03	20:05	0.0082	0.0082	3.12864	0.16	45.26	60.0*	
02/16/03	20:10	0.0090	0.0090	3.03070	0.15	45.41	60.0*	
02/16/03	20:15	0.0106	0.0106	3.40009	0.19	45.55	60.0*	
02/16/03	20:20	0.0052	0.0052	2.84323	0.13	45.64	60.0*	
02/16/03	20:25	0.0110	0.0110	3.48820	0.2	45.68	60.0*	
02/16/03	20:30	0.0062	0.0062	3.00309	0.15	45.6	60.0*	
02/16/03	20:35	0.0091	0.0091	3.36188	0.18	45.6	60.0*	
02/16/03	20:40	0.0089	0.0089	3.33204	0.18	45.55	60.0*	
02/16/03	20:45	0.0038	0.0038	2.82458	0.13	45.48	60.0*	
02/16/03	20:50	0.0088	0.0088	2.89528	0.13	45.45	60.0*	
02/16/03	20:55	0.0016	0.0016	2.64288	0.11	45.37	60.0*	
02/16/03	21:00	0.0100	0.0100	3.23950	0.17	45.33	60.0*	
02/16/03	21:05	0.0050	0.0050	3.15191	0.16	45.33	60.0*	
02/16/03	21:10	0.0077	0.0077	2.97227	0.14	45.27	60.0*	
02/16/03	21:15	0.0103	0.0103	3.40718	0.38	45.28	60.0*	
>02/16/03	*21:20*	*0.4474*	*0.4474*	*153.5163*	*344.86*	*58.77*	*60.0**	<
02/16/03	21:25	0.3548	0.3548	118.7151	207.49	54.05	60.0*	
02/16/03	21:30	0.2077	0.2077	67.95721	74.42	49.08	60.0*	
02/16/03	21:35	0.1158	0.1158	37.47577	23.2	47.09	60.0*	
02/16/03	21:40	0.0776	0.0776	25.04038	10.39	46.37	60.0*	
02/16/03	21:45	0.0542	0.0542	17.4571	5.04	45.99	60.0*	
02/16/03	21:50	0.0506	0.0506	16.28565	4.38	45.87	60.0*	
02/16/03	21:55	0.0408	0.0408	13.1133	2.87	45.8	60.0*	
02/16/03	22:00	0.0409	0.0409	13.13788	2.88	45.84	60.0*	

5.0 Well # 52 tool installation of the Beta tool [32" tool] took place in March of 2002 with, testing of two different tools in March through November of 2002. Gas gathering system pressure back up / increases in sales line backpressure were coincident with tool installation in March of 2002 and made initial tool runs and data interpretation awkward. Sales line compressor shut down [s] and service work effectively "pressured out" the tool from running for the first several weeks of operation and testing. During this period line pressures measured at 65 to 70 psi. Well head shut in pressures for # 52 during this same period measured as low as 85 psi. In general a 10

- 12-psi pressure differential between well and sales line is required to operate the tool. Note: This is as comparison to a typical 70-90 psi pressure differential needed for tubing plungers/ rabbits]. Tool runs during this period were sporadic and variable in terms of fluid production and post tool run gas production. Fluids production with tool runs [first tool] varied from 0 [zero] to 0.33 Bbls per run. Gas production for the period varied from a high of 14 mcf/d to a low of 7 mcf/d. At the maximum value the gas production and fluid production were similar to the predecessor first prototype BEDCO tool and much higher [>60%] than the standard casing plunger used in this well in 2000 and previous years and a considerable multiple over the unassisted production of 4-5 mcfd by natural flow. At the low production of 7 mcf/d the tool and well were producing on average 1 mcf/d less than the average production achieved by the standard casing plunger. All yields were greater than production historically achieved using tubing alone which achieved 3-5 mcfd.

5.1 Observations on the first generation beta tool runs, brine production and gas production from well # 52 during this period of unusually unstable line pressures over several months indicated a general decline in fluid production and decrease in gas production post each tool run. In all two different tools [the second tool at BEDCO cost and expense, as it was not budgeted for in the SWC work plan] were subject to in well/ in field-testing. Both evidenced a similar pattern of performance in well # 52. As such, this portion of the test was reluctantly terminated in early August of 2002 and the tools were returned to BEDCO facility for preliminary evaluation. Physical observations of the prototype tool valve assembly indicated a misalignment of the valve and valve seat. This mis-alignment appeared to stem from the size reduction efforts, which removed certain valve stem guides. This misalignment alone did not preclude tool operations when bench tested both pre and post well installation and operations. The second more profound discovery of ex-situ well, in laboratory, testing was the appearance of slow pressure loss from the actuator assembly. This pressure loss was observed to occur over a period of hours to days on the tools used and retrieved from well # 52. As the actuator is a sealed system, the immediate source of the leakage/ failure was not readily apparent. The actuators were returned to the manufacturer for destructive analysis testing. Upon arrival at the manufacturer, the actuators were first re-subjected to a water bath pressure test to confirm absence of integrity as found in the BEDCO facility. Confirmation of pressure leakage from the assembly was made. The actuators were subsequently disassembled and examined under high magnification. This examination revealed corrosion holes in the actuator. The location of the corrosion holes were located on the stainless steel side of a Hastelloy- stainless weld line. Both tool actuators showed a similar failure pattern. Research into the problem shows an elevated corrosion index potential between Hastelloy and stainless steel metals. This corrosive potential in the construction of the actuator was compounded by the welding of the stainless steel to the Hastelloy and certain physical restrictions in the fluid passage through the actuator which caused brine [15 – 20 % NaCl] to accumulate adjacent to the welds where the corrosion effects were concentrated.

5.2 A further design change and manufacturing change was made in the tool actuator to off set corrosion problems. This tool w/ new built actuator was constructed and sent to well #52 in late August of 2002

5.3 Performance of the tool started as designed with ~ 1 Bbl of fluid per cycle and an approximate 60% gas increase. Cycle frequency deteriorated and yield declined. The tool was removed for lab testing in Late November. Preliminary evaluation shows no corrosion problems but a mechanical binding of actuator components. It should be noted herein that upon completion of each test of the 32" tool in LRI # 52, the predecessor 51" tool was re-deployed to confirm function of the TOOL in well # 52,

absence of any changed conditions and the applicability of the design. Each time the 51" tool quickly stabilized production and tool cycling and fluid removal. Tool cycle frequency is generally at 1 to 1.5 days with production of 0.75 to 1 Bbl of brine and increase gas yield to 12 to 15 MCF for the well vs previous at 7 mcf or less.

5.4 January of 2003, a 4th Beta type tool was manufactured and installed in well # 52. This tool incorporated components and elements of previous tested tools in a slightly altered physical format. The tool actuator was set to retrieve ~ 1Bbl of fluid/ tool cycle under operating sales line back-pressure of ~50 psi. The tool performance was as targeted by the design and in keeping with bench test results. The well produced approximately 0.75 to 1 barrel of brine per cycle with back-pressures in the range of 50 to 60 psi. Yield at the well was recorded at 12 to 14 Mcf/d as compared to previous 6 to 7 Mcf/ d averages.

5.5 Well # 29 tool installation [32" tool] initially took place in July of 2002. The tool was installed in a well, which was plumbed to a gathering line with its own compressor system which theoretically should have been able to maintain a stabilized pressure. Manpower limitations in service of the compressor plagued the operation for the first 4-6 weeks of the test. Operating pressures were subsequently stabilized and the tool made several automated runs. The first of the runs was at the targeted fluid removal rate of 0.75-1.0 barrels/ run with subsequent runs at lesser quantities of fluid until the tool ceased automatic operation. The tool was retrieved via blowing the well to the brine tank and catching the tool in the catcher built into the lubricator. No external assistance was required to retrieve the tool.

5.6 Bench test analysis proved to show lost pressure in the well # 29 tool actuator. Destructive analysis of the actuator proper revealed a corrosive failure at the Hastelloy/ Stainless interface as with the 1st and 2nd tools deployed in well IRI-52. The redesign and reconstruction of the actuator as noted for well LRI # 52 was developed and was further refined for further in filed successful testing.

5.7 Tool design modifications were made. These modifications include a support mechanism for the valve and valve seat assembly, which improved alignment and increase concentricity of valve and seat in the tool. This further reduced potential for seating problems or leakage of the valve once closed and sealed. The more important remedy is a metallurgy change in the contact area [reduce corrosive index potential] between the stainless steel end fitting and the Hastelloy actuator. This metallurgy change was coupled with a physical modification to the actuator which eliminates blind passages in the tool, which can trap brine and there by concentrate their corrosive effects. BEDCO has self-funded these design modifications and manufacturing of new actuators outside of the SWC sponsorship on the project. Further mechanical modifications were warranted based upon response of the tool deployed to well LRI # 52 in August-November 2002. These design modifications were fitted to the tool with initial lab and field-testing in the first calendar quarter of 2003. As noted above the results for well # 52 were on target with design basis and bench tested results.

5.8 Post the determination of the first generation Beta type [smaller tool] actuator under performance in August through November of 2002, BEDCO re-installed [as noted above] a predecessor larger tool [51" tool] in well # 52 and LRI # 29 to confirm applicability of the technology. This earlier version, larger, somewhat more cumbersome, tool was deployed in late August of 2002 and again late November through December of 2002. The tool was set with an increased actuator pressure to accommodate accumulated brine not removed during the previous testing. The tool target was to retrieve 0.75+ Bbl of brine on each tool run at 60 psi of sales line back-

pressure. Observations during the month of September 2002 showed 5 to 7 tool runs per week yielding 0.75 to 1.0 Bbl of brine per trip. Gas yield after each of the trips averaged14.5 - 17.5 mcf/d. The brine production is ~ 2 fold greater than during previous tool test and gas yields ~ 15 to 20% greater. Comments by the well tender post the old tool re-deployment were, "gee that well just gets better and better". Similar results were achieved during October through December of 2002.

5.9 Well # 29 was re-tested with a 51" version of the tool to confirm applicability of the technology. Testing was re-initiated in mid-January of 2003 and continued through end of year. The tool was initially set to retrieve 1.5 Bbl of brine/ tool cycle at a back-pressure of 30-35 psi. Well performance prior to G.O.A.L. tool installation was at ~ 5Mcf/d. Post tool installation, the well production increased to 10 Mcf/ day while producing 1.5 Bbl of brine per cycle. Severe cold and icing in the well head lubricator caused the tool to become lodged in the lubricator once each 2 to 3 trips. After a month of operation at the 1.5 Bbl/ trip rate of brine production, the actuator was re-set to lift 2 Bbl/ cycle of brine. Post this adjustment to the tool a 2 Bbl/ cycle was achieved and the well yield increased to a stable 13Mcf/d. This well was subsequently fitted with a beta 32" tool and achieved similar results.

5.10 The first Oil and Gas well tested was # 341 which was initiated using a version of the larger [51"] tool in July of 2002 to accommodate accelerated passage downward through the oil. The tool was set up for the reported operating conditions of the well to produce 3 to 4 Bbls. of fluid per cycle. Actual well operating conditions proved different than recorded and predicted. The tool made 2 partial tool runs producing small volumes of fluid [2 barrels] and then produced one run yielding 41 Bbls. of total fluids comprised of a 40/1 BBl. ratio of oil to brine. The tool was retrieved. The actuator in the tool was to be set at a lower pressure to attempt to accommodate the different [lower pressure and faster fluid accumulation rate] conditions of the well. Prior to the ability to re-deploy the tool weather conditions made access to the well non-tenable [non all weather road]. The well operator suggested postponing the test until the road was once again trafficable to remove oil and fluids produced by the tool. The tool was retrieved for use in another [to be selected] test well.

5.11 Additional Tool/ well testing with the newest 32" Beta tools was completed through out 2003 and 2004. The evolved tool design and construction incorporated improved metallurgy, improved seal cup formulation/ configuration, and improved internal alignment for valve seal and seat. The wells tested and results achieved are contained in the following table.

Table # 4

Evaluation of Well Performance with G.O.A.L. PetroPump

Well designation, Geologic setting and Depth	Pre GOAL Production/ Methodology	Post/ with GOAL tool Production	Fluid Production Qty./ Frequency	Comments
LRI-52. Medina Fm., tight Sst @ 3300'	**4-5 mcfd w/ tubing,- 7 mcfd w/ standard casing swab**	**13-15 mcfd post domestic/ farm consumption and non quantified off chart production Fig. # 3**	**~4 Barrels/ week @ 1 to 4 runs daily- ,down hole 95 psi,- line 55 psi average**	**~ $60K+ Rev- over test period. Stable freq. runs& prod. [~230M/ month not recorded off chart and Agra business consumption] Fig. # 2**
LRI -29, Median Fm. tight Sst. @ 2390'	**4-6 mcfd w/ tubing, -7 mcfd w/ std. casing swab**	**13-16 mcfd**	**1 barrel/ day, @ 1 tool run/ day-, 105 down hole psi,-line 30-35psi**	**Very stable production and tool run frequency- no cup changes in > 1 year, 2+ years test. Est. $20K + Revnue**
LRI- 332, Median Sst. @ 3350'	**3-5 mcfd w/ tubing, 7-8 mcfd w/ std, casing swab**	**18-22 mcfd**	**3-6 Barrels/ wk. @ 1-3 runs/ day-, down hole 110-115 psi,-line 50-55psi**	**Tool removed- well gave back frac sand- tool retrieved w/o external assistance, tool operated ~ 9+ mo. w/ out prblms.**
LRI- 54, Median Fm, tight Sst, @ 3250'	**3-4 mcfd w/ tubing, 5-6 mcfd w/ std casing swab**	**5-12 mcfd- very erratic automatic operation- always retrievable by venting to tank**	**1-5 bbls/ week, irregular runs, 2/ day to 1/ week, down hole 120 psi,-line 50-65 psi**	**Down hole casing problem suspected with periodic loss of press. causing tool stalling**
LRI-341, Bass Island [oil and gas[carbonate well @2800'	**Pump jack- 3.5 Bbls oil/day & 3-4 mcf/d gas**	**Post tool runs gas not quantified- automatic runs achieved**	**2- 41 Bbls/ run, - 41 bbl run [40-1 ratio oil to water] run, gas not quant.- follow on pressure @ 350+ psi**	**Site volume storage problems- road access problems- test terminated- tool re-deployed**
LRI-274, Median Fm, tight Sst @ 3400'	**1-2 mcfd w/ open hole**	**6-8 mcfd, erratic production, did not get ahead of fluid production**	**1-4 bbls/ run,- down hole 400 psi, -line 60-65 psi follow on tool run pressure increasing wh. test terminated**	**Infrequent service during start up by well tender, well subsequently sold- tool removed**
C-14, Red Medina, Sst @1355'	**10-15 mcfd w/ velocity string**	**15 + mcfd insufficient frequency of data collection/ sales line pressured up to > 220 psi**	**Several tools run made both automatic and manual- down hole casing problems**	**Well tubing encrusted and of variable diameter, tool/ cup binding- infrequent runs**
C- 35, Red Medina, SSt @ 1395"	**15- 20 mcfd w/ velocity string**	**Sales line pressure max'ed @ 230 psi shortly after tool install- no compressor on line**	**Tool runs made by shut in well and blow to tank- down hole well diameter problems [variable/diameter]**	**Well tubing encrusted, inadequately scraped, casing of variable diameter- tool/ binding**

RMOTC 12-AX-11, Second Wall Creek Fm, Sand @ 3162'	29 mcfd w/ pump jack for fluids @ 1-2 Bbls/ day	-----------	-----------	[1]Fluid level to low-below perfs in open hole [2] pressure differential marginal @ 15-20 psi
		Table 4 Continued		
Well Designation, geologic setting & depth	Pre GOAL tool production/methodology	Post/ with GOAL tool production	Fluid Production Qty./ frequency	Comments
RMOTC 35-AX-34, Second Wall Creek Fm, @ 3017'	1.7 BF/D & 60 mcfd w/ pumpjack	-----------	------------	[1]Fluid Level to low, below perfs, [2] pressure differential in sufficient
RMOTC 38-1AX-34 Second Wall Creek sand @ 3185'	3.3 BF/D & 60 mcfd w/ pump jack	-----------	------------	[1]Insufficient fluid above safety stand to set tool [level too low]
RMOTC 36-MX-10, Muddy Fm, Sand @ 4063'	1 BO/D,5.5 BW/D & 150 mcfd gas w/ pump jack- 0 fluids and 0 mcfd natural flow	-----------	-------------	[1]Well prep. left residual paraffin and scale down hole- tool could not reach fluid- [2]well re-cleaned- [3]cups swell in aromatic oil- [4]new aromatic resistant cups added tool damaged on re-deploy-no seal
SR- 2023, Medina FM, tight Sst @ 2625'	3-5 Mcfd open hole w/ periodic swab production flow	15- 25 mcfd	1-2.5 Bbls/ wk, @ 3-6 runs/ wk, down hole pressure @ 90 psi,-line pressure @ 30-40 psi	~ 12 months of operation, well has given back frac. sand- tool still operates @ smaller increase of 450 mcfm vs tool initial of 750 mcfm
SR- 1984, Medina Sst 3077'	5-6 mcfd open hole periodic swab production	20-35 mcfd	2-4 Bbls/ wk @ 1 run/ day to 1 run/ 2 days	6+ months of uniform tool operations and stable production
CWD St#3 Grimsby/ Whirlpool @ 2120'	1-2 mcfd w open hole and periodic swabbing-	2-6 mcfd	1 run each 1.5 to 2 days @ 4 to 8 Barrels/ fluid/ run, down hole pressure @ 400 psi,-line @ 45-60 psi, well dead @ 50 psi- post tool run pressure @ 215 psi and on increase	Test curtailed as brine production storage exceeded [40-50 Bbls of brine/ week], production was on increase & post run follow on pressure increased- other wells in group will be tested with les excessive brine production

5.12 Qualitative evaluation and limited comparison of conventional brine/ fluid removal techniques commonly deployed in similar wells to the chosen test wells is given below as a compilation of information in an anecdotal format developed from interviews with well operators.

Existing methods for brine removal in Stripper wells more commonly include:

[Note: These methods are common to many Geologic Fm. and wells]

- **Periodic swabbing with a "work over" rig to remove accumulated brines and temporarily restore gas flow, requiring a normal two man complement, appropriate swabbing tools, equipment and investment of several hours total time for a 3000 to 4000' well. Effects of the intermittent fluid removal are noted to last a few days to weeks before yield again declines due to water off of gas. Cost of service ~ $300- $700/ event [assumes less that 3-4 hours per swab event]. Capital cost of equipment $30,000- $50,000.**

- **Installation of casing swabs that operate by dropping of the mechanical operated casing swab to a preset stand. When the tool strikes the stand it mechanically closes a valve regardless of the height of column of fluid atop the tool and regardless of the pressure below the tool to lift fluid column and tool weight to the surface. These types of tools normally require manual release and often man assisted recovery. Normal capital cost $5,000- $7,000 for tool assembly & man assisted operation. Automation [well head] additions $1,500- $4,500. Limitations are the tool must go to the stand to be activated and then be capable of lifting the entire column of fluid atop the tool to the surface. This tool is not able to remove fluid accumulation in increments [all or none].**

- **Installation of smaller diameter tubing in 4 to 6 inch wells [commonly 1.5 to 2.5" internal diameter tubing] targeted to allow older production gas wells with declining volume and reducing pressure to lift accumulating fluid from the well to the surface via combined capillary action/ velocity increase in the smaller tubing. This technical approach is often employed with the periodic shut in of the well to increase down hole pressure to a level sufficiently high that upon reopening of the well will purge the tubing of the brine/ fluid column. This method also often employs the use of surfactants "soap sticks" to disperse the brine into a foam and "lighten" the fluid column for purging to the surface, the process unit and the brine tank. Capital cost for steel tubing for a typical 3000' well are $6000- $9000 plus installation @ $1500 and periodic shut in and opening by man. Limitations are that a critical pressure must be over come and a critical velocity of gas an fluid must be maintained to purge the well of its fluid. Post each purge the well flows for some finite period at the end of which the well is shut in to build pressure and repeat the process resulting in intermittent gas production.**

- **Tubing plungers/ rabbits are another technology deployed to produce gas from these types of stripper wells via the periodic purging of fluids from the tubing column. The rabbits are in general a smaller version of the mechanical swab tools with greater associated mechanical challenges [need to maintain elevated pressure differential of > 80 psi and elevated fluid/ tool movement velocity to avert stalling and fall back of tool and fluid as well as man-assisted operation and or well** head controls. Tubing cost for a 3000’ well are as noted above $6000- $9000, rabbits systems can vary from ~ $1000 to $4000 with well controllers.

- Pump Jack [Beam Pump] rods, down hole pump and tubing are the historic time honored method for lifting fluid from wells. Capital cost for a 3000’ hole are on average $15,000 for Pump Jack, tubing, down hole pump and rods. External power is required with annual O and M cost estimated at $2500- $5000/ year for such a well

All these above technology assisted improvements for fluid removal have a common need for manpower assistance and or some add on well external pressure or electronic activated semi-automated controller. Dropping and retrieval of tools [casing swabs and rabbits] involve the need for periodic service [release and retrieval] by a well tender or well head controller, down time on the well production and or some external assistance such as mechanical or electric timers for dropping of tools. Periodic swabbing by a work over rig is the most labor intensive and least cost effective of all methods. Tubing and soaping to lift fluids similarly results in well production down time during periods of well shut in to build pressure to purge the well and also require appropriate manpower. Pumps jacks have elevated cost and on going significant O and M cost associated with energy consumption and operating components wear.

Interviews with well tenders and operators alike when questioned, what dictates the frequency of servicing a well where one or the other of the above technology is deployed? Most record a common refrain, “When there is sufficient time to get to it [the well]”. Most well tenders interviewed were found to be servicing 50- 80 stripper wells, some more. As such production is highly dependent upon the frequency of service by the operator and punctuated by periods of non-production and spike production.

One such interview on frequency of service and method of operation with a well tender of more than 30 years experience focused on his experience with the most comparable [albeit not operationally comparable to the design and operational results of the G.O.A.L. PetroPump] technologies of casing swabs/ mechanical swabs/ ‘dumb swabs. Questions posed to operator were simply when and how do you decide to deploy or “Drop” a mechanical swab tool and what do you do if problems arise with it cycling/ returning to the surface with brine:

- The candid response was, as a conscientious operator he tries to inspect the well every two to three days and make a qualitative determination of well production and wellhead pressure. At such time as he determines from his inspection and interpretation of the process unit analogue volume/ flow production chart, pressure reading at the process unit and possibly a well head pressure reading that production and pressure are not acceptable [i.e. gas flow volume down and pressure down based upon qualitative assessment], the mechanical swab tool is physically released from the catcher to the well.
- The well is then next inspected one or two days in the future. The inferred reasoning on this lapse in time frame is that the tender has previous empirical experience indicating, that is the approximate time it takes for the tool to make a ‘run’ [i.e. return to the surface with fluid] in that the mechanical tool must drop completely through the accumulated fluid column to the well stand to set the tool/ close the mechanical valve before it can initiate a run. This presupposes that the fluid column is sufficiently short and the below mechanical tool pressure

sufficiently great to lift both mechanical tool and column of fluid to the surface for processing [often not the case].

- If/ when the mechanical swab tool does not return to the surface, the base interpretation and common empirical experience indicates that this is due to the fact that the pressure behind the tool is insufficient to lift tool and fluid column atop the tool.
- Follow up actions to retrieve a stalled mechanical swab tool can vary and usually evolve from the simplest response of “shutting in” the well to build down hole pressure for 1 to 2 day [s] with subsequent release of the pressure rapidly directly to the brine tank. More involved and evolved actions can include the addition of a surfactant, shut in of well to build pressure and subsequent purge to brine tank to the more complex action of tool retrieval techniques using other mechanical equipment and tools.
- This non regular purging of the well of the fluids and often long periods of low to no gas flow resultant from stalled mechanical swab tools is referenced to periodically lead to down stream effects such as winter icing of the process unit further reducing gas output from the well.
- The well tenders’ summary of operation of wells with mechanical casing swabs is that it tends to produce gas from the well in an uneven and punctuated manner. There are further frequent periods of well down time leading to less overall gas production than the well is capable of were the brine uniformly and regularly removed.

5.13 Significant Accomplishments under this contract Subcontract No.2052-BEDC-DOE-1025 A-3

- Reduced tool size to 32” length, weight to 42# and total parts to 14, a collective 50% miniaturization from ancestral tools
- Developed metallurgical compatible components with down hole fluids for key “Actuator” automated on tool control component
- Achieved ~ 98% compliance of machined parts and components with design spec and lab to field operational performance
- Designed, developed molds, constructed and successfully deployed a new 4” OD “Cross Banded” cup with improved seal fit for passing in well collars with reduced pressure/ fluid loss and increased longevity of cups. Note: Some Brandywine tools have made hundreds of tool cycles on the same set of cups, a key seal/ lift/ wear [former wear] component.
- Designed, developed and successfully deployed and operated a 4/3 convertible tool for use with 3” and 4” ID tubing around a standardized field tested Actuator automatic control with new BEDCO “Cross Banded” cups.
- Designed, developed and constructed molds and cups for 3” ID and 5” ID tubing for broader tool application in stripper wells
- Successfully deployed and retrieved the tool in more than 8 wells and found the tool in post application use [current model] to show little tool and or cup wear and be with in 0.5%-3% tolerance of original specification and settings after use.
- Developed concept plans and designs for re-fitting large diameter and or open hole completed wells with non-metallic tubing and 3”, 4” and or 5” versions of the GOAL tool affording the opportunity for greater production at lower down hole pressures and re-completing wells with non metallic tubing. Challenges for actual field completion include metal to non metal connectors at well head

and down hole anchor, as well as “New Flex Wall” cup capable of 0.5” OD diameter change w/ out loss of sealing properties

- In an on going march toward commercialization of the tool system Brandywine has developed a Web site with on Web Site tool animation/ operation sequence, on line well data quantification sheet for potential customer response/ tool application, trade show tools, demonstration elements and response offering in field testing.

Project Schedule

Task Performed	Year- Quarters [2001][2002][2003][2004]
Design tool/ modify design	>>>>>>>xxxxxC
Construct Proto/ Beta type tools	>>>>>>xxxxxxxxxxC
Select Candidate Well [test]	>>>>>xxxxxxxxxxxxxxxxxC
Bench Test Tool	>>>>>>>>>>>>>>xxxxxxxxxC
Test Well Production	>>>>>>> xxxxxxxxxxxxxxxxxxC
Evaluation of Performance	>>>>>>>>xxxxxxxxxxxxxxxxxC
Evaluate/ Estimate/ Recommend	>>>>>>xxxxxxxxxxxxxxxxxC

Key: >>>> -Original scheduled time frame
xxxx -Revised time frame to complete
C -Completed task

6.0 EVALUATE ECONOMICS

6.1 Potential economic payback from the use of the GOAL PetroPump is estimated below from results of current beta tool production increases in the LRI # 52 well, LRI # 29, SR 2023 and SR 1984. This data used in the base calculations was derived from operations in 2001 through 2004. As noted above in an earlier section, redeployment of the predecessor [54” tool] tool in well # 52 and LRI # 29 had improved production in the month of September and October 2002 to an average of 17.5 mcf/d [note this is during a period of lowest pre meter gas consumption by the local Agra business tapped into this well. Recent average production for this well [normal to elevated Agra business consumption] with the newest Beta tool [a 4/3 convertible tool] is 13 to 15 mcfd. This well was chosen as it represented the first well chosen for tool deployment, the longest history of under GOAL Tool production and among the lowest yielding wells pre GOAL Tool deployment.

6.2 Estimates of Payback from Production

Assumptions:

- “Tool” Cost and Well Modifications @ $13,500.00
- LRI # 52 Monthly Average Production with Tubing @ 98 mcf
- LRI # 52 Monthly Average Production with ‘ Std. casing plunger’ @ 252 mcf
- **Value of gas @ $5.00 mcf**

Table 6-2 LRI # 52 Well Performance- Pay Out

Ave. Prod. using GOAL Pump	Ave. Prod. using tubing in 1995	Average Prod. Using 'casing plunger'	Payback @ $5 mcf vs tubing production	Payback @ $5 mcf vs 'casing plunger production
381 mcf month	98 mcf month	252 mcf month	~9.5 months	~21 months

Table 6.3 Pay Out on Other Example Wells Tested Using Improved Production from GOAL Tool only. [Base production from prior operation subtracted as with LRI-52]]

Well and Prod. w/ GOAL Pump	Pre- GOAL Pump Production- method	Pay Out @ $5/ mcf w/ tool Cost @ $13,500	Comments
LRI-29/ 360 mcf-month	210 mcf-month w/ std. casing swap	18 months	The GOAL pump has operated in this well for more than 1 year w/ out change of seal cups
LRI-332/ 540 mcf-month	180 mcf month with standard casing swab	~ 7.5 Months	Well gave up frac sand/ tool recovered w/ out external assistance
SR 2023/ 475 mcf-month	150 mcf month with periodic swabbing w/ rig	~ 8.5 Months	1]This well has produced as much as 750/ month w/ tool- 2]frac sand currently slows tool runs & production to ~ 450 mcf/ month
SR 1984/ 750 mcf-month	180 mcf-month w/ periodic swabbing w/ rig	~ 5 months	Well has regularly produced up to 30-35 mcf/d when down stream compression stable

It must be noted that the pre test yields of most of the wells tested were very small [~3+ to 7 mcf/day of gas via tubing, standard casing swab or open hole/ swab operation at initiation of test] in comparison to the average gas stripper well in the US @ 15 mcf/ day. Half of these wells, even with the improvements yielded by the G.O.A.L Petropump are at or below the average US gas stripper well production. Application of the Tool in wells with greater initial production and potential [i.e. the average stripper well] which have need for regular automatic brine [fluids] removal should yield better results and quicker payback on capital invested in the tool. The current cost of the Tool at approximately $13,500 complete with wellhead modifications for installation is not inexpensive for stripper wells. This is due to proprietary construction materials and techniques. Production of Tool in a commercial manner may reduce cost. Improvements in Natural gas and crude oil price increases can shorten payback on capital investment for the Tool user. Finally the uniqueness of the G.O.A.L PetroPump and its on Tool self-actuating controls to regulate frequency and volume of fluid removal from wells differs greatly from casing plungers, tubing plungers, siphon tubes, velocity strings and pump jacks producing superior results in these test and has its own unique market niche. Reduction in O and M cost further benefit the use of the GOAL Pump with its limited number of moving parts and increased life seal cups [> 1 year in field trials].

6.3 Cost Comparisons to Other Alternatives

Cost comparison of the G.O.A.L. PetroPump to the common used equipment for fluid removal from gas wells in the depth range of 3000' to 6000' would include:

- Pump Jack/ Beam Lift, associated sucker rod, tubing and down hole pump can have capital cost in the range of $15,000 - $40,000. Operating cost for pump jacks range from $2000 to $10,000/ year depending on volume and type of fluids produced, maintenance, replacement parts and service required.

- Tubing string production could have $6,000 to $15,000 capital cost dependant on tubing diameter and operating cost ranging in the $1500- $3000/ year for manpower & surfactants.

- Casing plungers' capital cost with the necessary well head modifications to receive the unit are in the range of $5000 to $7000 capital. Additional capital cost for well head controllers for any attempt at automation of casing plungers is also needed [as opposed to man assisted runs], at $1000 to $5000. Operating cost would include manpower at a minimum of $500 to $1000/ year to $2000- $3000/ year on manual run tools. Work over cost to retrieve drowned and or stuck tools are not herein quantified but typical rig/ day cost are $750-$1000.

- Tubing plungers [Rabbits] base requirements include the installation of a tubing string at $6,000 to $15,000 as noted above plus the capital cost of a Tubing plunger at $1000 without any automation to $4000 with automation [semi] controls. Operating cost are not dissimilar to casing plungers noted above at $1000 to $3000.

Further with respect to casing plungers [must strike down hole stand to set tool and lift total fluid column] and tubing plungers [minimum ascent velocity required for tubing plungers], they do not operate in the same or similar fashion to the G.O.A.L. PetroPump with on Tool controls and down hole/ up hole smart Tool technology.

In terms of applicability of this G.O.A.L. Tool to wells in the immediate test area of New York State. It was determined that approximately 3,523 gas wells and approximately 529 active oil wells exist in Chatauqua County, New York where 5 tools were tested. Based upon our exposure to the wells in the area it is likely that 50% or more of these wells will have fluid production related problems in the life of the wells. It is further likely they will require some form of tool related technology to produce gas and or oil. Assuming the G.O.A.L. PetroPump Tool would serve 1/3 of the wells in need of tools for enhanced production some 500 to 600 wells would be candidates for the GOAL tool in Chatauqua County. Projecting those numbers to the entire state of New York production could mean more than 1500 tools for state of New York wells.

Assuming only an 8-mcf/d increase per well [in range of test increases] at $5/ mcf could yield >$21,000,000 in gas value and a pay back on 1500 tools at $13,500/ tool in a one year time period.

Were one to use the average increase from the SR wells # 2023 and 1984 where the increase was ~ 15 mcfd for each of the wells pay out could be achieved in ~ 5 to 6 months.

6.4 Over the recent years several organizations have begun to evaluate the number of stripper gas and oil wells in the United States which exist and are troubled by water production. BEDCO's review of the number of wells for which the technology being developed may be applicable is derived from several sources. Those specifically referenced here in are:

- **National Survey – Marginal Oil and Gas Report by IOGCC [Annual]**
- **Ohio and West Virginia Survey – University of Kentucky by E. Choong**
- **New York – IOGANY Marginal Well Study sponsored by NYSERDA 2000**

6.5 Results of review of those above referenced documents by Brandywine indicate nominally ¼ to 1/3 of all stripper wells as potential candidates for the use of the standard 4.0" OD tool. Current total numbers of stripper wells in the lower 48 states of the US is in excess of 630,000 with an approximate 1/3 of them gas wells to 2/3 oil stripper wells. With the increase in natural gas demand in the past decade there is a growing number and percentage increase of gas stripper wells vs. oil stripper wells in that mix.

6.6 The applicability of the GOAL tool to a larger number of those above referenced stripper wells may be accommodated as technology improves to re-fit wells with failed or irregular casing, current open hole and telescoped casing completions with spoolable non-metallic tubing and a down sized- variable diameter "Flex Cup" version of the GOAL Pump 4/3 @ 3.o" OD configuration.

6.6 As specific example of some of the wells tested during this contract include those at the RMOTC facility north of Casper Wyoming. These wells are 5.5" OD with fluid levels currently at or below the perforations to below casing. These wells could be sleeved with 4.5" OD spooled non-metallic tubing [or 3.5" OD and the in planning GOAL 4/3 tool which is convertible to a 3.0" OD tool] affording opportunity for a GOAL tool to operate at several hundred feet greater depth [potentially in the spaceous rat hole]. At those depth in those wells sufficient fluid would be available atop the tool to set the internal actuator closing the valve; further the spoolable synthetic tubing would afford less friction loss and greater lift potential resulting in more total fluid and gas produced from the reservoir and lower ultimate abandonment pressure and left behind reserves.

6.7 A similar opportunity affords itself for the Chatham wells [Cdn] C- 14 and C-35 which have a telescoped variable diameter casing which caused cup/ tool binding and erratic tool runs and shut downs.

6.8 In Brandywines' review of potential stripper wells for tool application, tens of thousands each of; open hole completions, telescoped completions and wells where fluid level was at or below perfs and down hole pressure/ pressure differential was marginal for current tool configuration and standard casing configuration could be self pumped with the now being developed 4/3 GOAL Pump and a re-fitted length of non- metallic spoolable tubing. Additional field work is needed there on to gain in field oil and gas industry acceptance and field prove out bench results.

6.9 Further to the applicability of the GOAL Pump to industry needs, a GRI study by Spears indicates > 200,000 stripper wells in North America producing < 25 barrels of

fluid/ day. This 25 barrel/ day quantity is with in the current empirically determined lift capacity of the standard GOAL PetroPump.

CONCLUSION

The need for and applicability of a Gas Operated Automated Lift PetroPump [A Smart Swab Tool] for removal of fluids from a significant percentage of stripper wells we believe has been proven by this field applied research for the oil and gas wells of America and the world. Key elements of the GOAL tool leading to increased production and automatic pumping are its unique on tool variable lift actuator [it does not have to go to the base of the well to be set], resilient long life tool to casing seal cup and abilities to work in varying geologic environments of pressure, depth, fluid production, in well chemistry and operating conditions. Current target wells for which the tool is readily deployable and serviceable in 4" ID wells; with but minor structural changes to the well head and process units to be economically viable. Increased yields of 1.5X to 4.0X + have been achieved in this field test on wells whose base yield was 7 mcfd or less. Empirical data from the test has shown that in the wells tested the greater the base yield [pre GOAL tool] the greater the post tool gain in production with achievable payback on the tool at a current price of $13,500 achievable in 5 or less to~ 12 months for those low yield wells tested.

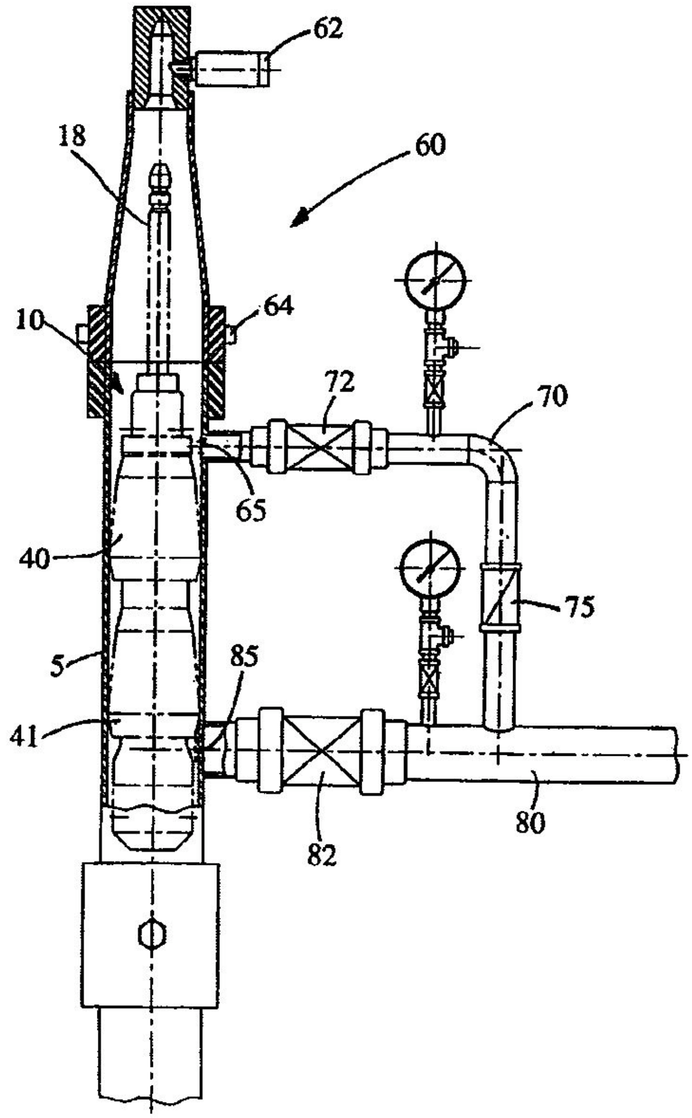
Future needs of such a Gas Operated Automated [lift] Tool will target wells with 3.0" diameter tubing, telescoped variable diameter casing and or open hole/ large diameter completion wells or open hole completions that could be retrofit with isolation packers and continuous smaller diameter tubing than the nominal open hole diameter of 6.25".

Bench and test stand testing of varying automated valve closure assemblies and engineering calculations and field test indicate potential operating ranges for the prototype and beta type tool at 50 to 600+ [psi] and potential fluid lift of 0.1 to 9-+ bbl's per tool cycle. Field trials of the prototype and beta tool have confirmed the ability to operate through out these bench-tested values. Note: Field empirical data does show at least [1] one 40+ barrels lift without tool and or cup damage.

Automated computerized well head data loggers show they can record varying location pressures at the well head and process unit, as well as continuous volume of production. These units have evolved to a point to be applicable for in field continuous recording of operating conditions of the GOAL tool. This data can serve to act as basis of tool adjustment for optimum performance and to target tool components for upgrade and improvement. These type of instruments with large variable input pressures and rates of flow can also more accurately capture total gas produced and diurnal and long term trends in gas and fluid production. Note: Use of one such unit on a tested well evidenced some 20- 40 mcfm as not being captured and/ accounted for in an industry standard analogue meter and pie chart following automatic tool runs. At gas prices of $5/ mcf or greater this could represent ~$1200-$2500 annual revenues which could foster even quicker payback on the GOAL tool when and where employed.

On a national basis tens of thousands to perhaps 100,000 or more of stripper wells appear applicable for use of the technology to improve production. Production increases even if equal to low range of the GOAL tool results [7 mcfd] on 10,000 wells can amount to >120 millions of dollars worth of additional recovered energy resources annually at modest well head re-configuration and G.O.A.L. PetroPump cost which could be recovered with in < 1 years based upon recent filed tool test results. Tool modifications and improvements can make the tool more durable and better functioning to further increase performance and shorten pay back on capital tool investment and more widely applicable to more wells.

FIG. 1



BEDCO G.O.A.L. PetroPump Schematically Shown in Well Head Lubricator

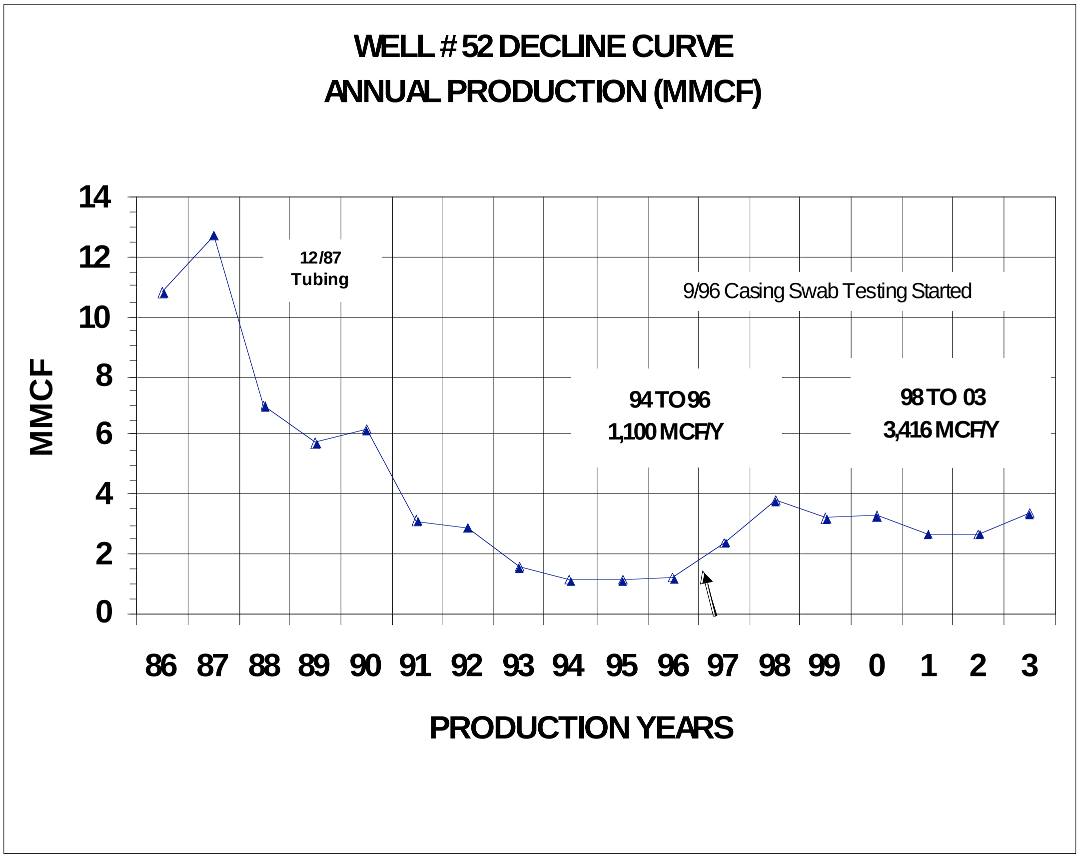


Figure 2: Annual Gas Production From LRI Well #52, Before and After GOAL Tool Installation

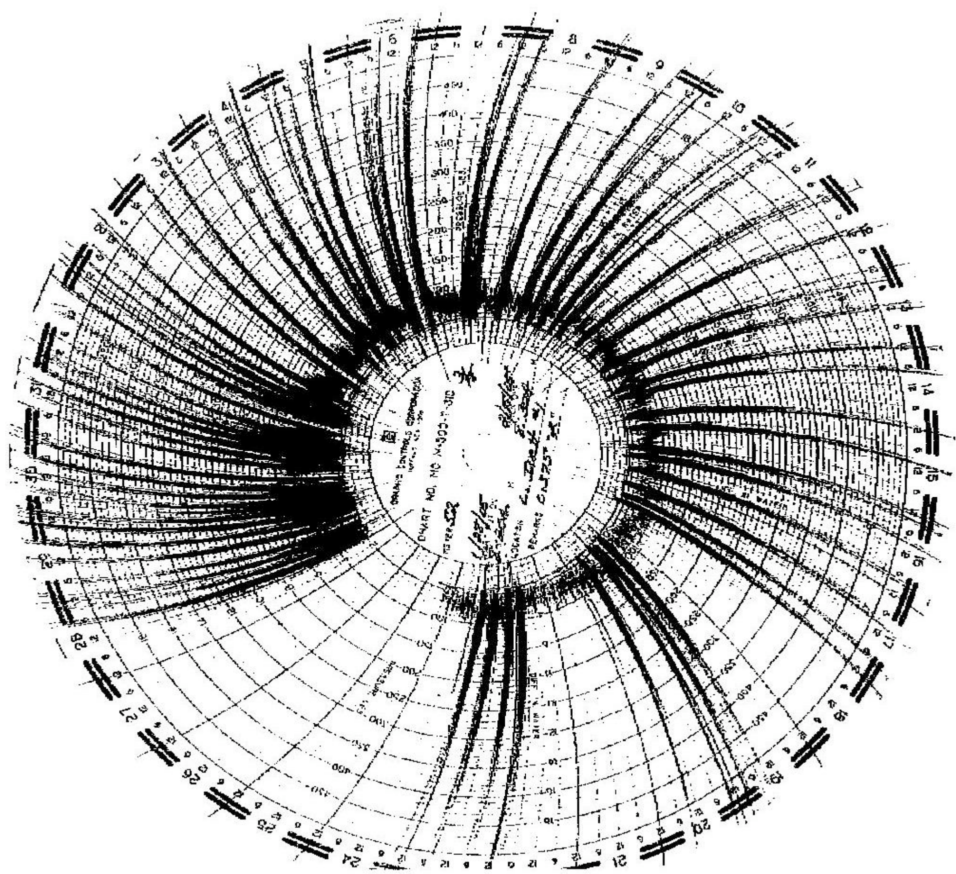


Figure # 3

Typical Well Production Chart Showing GOAL Tool Runs on LRI # 52

Notes: 1] Analogue Pie Chart for well LRI, Feb 2005
2] Tool runs = Spikes on chart @ ~ 50+ trips for the month
3] Three + [3+] days well down due to process unit problems
4] GOAL Tool deployed newest version 4/3 Tool in 4" mode w/X-banded cups

Appendix 1

Table 1 - 1 Tested Well # 52

Test Period	1996/1997	2001/2002
Completion date	11-1-83	11-1-83
Formation	Medina [Grimsby/ Whirlpool]	Medina [Grimsby/ Whirlpool]
Geology	Sandstone [tight]	Sandstone [tight]
Total Depth	3,343 feet	3,343 feet
Perforations	3,127 – 3,229 feet	3,127 – 3,229 feet
Casing size	4.5”	4.5”
Production prior to test	3 mcf/d via tubing	8mcf/d w/ casing plngr. tool
Well head pressure	320 c/ 60 t psig	180 psig
Line pressure [sales]	60 psig	55 psig
Bottom Hole Temperature	97 deg. F	-----

Table 1 – 2 Candidate Test Well # 29

Test Period	2002
Completion Date	1982
Formation	Medina [Grimsby/ Whirlpool]
Geology	Sandstone [tight]
Total Depth	2390
Perforations	2299 – 2370
Casing size	4.5”
Production prior to test	~9 mcfd w/ std. casing plunger tool [4-5 mcfd w/ natural flow
Well head pressure	150 psi
Line pressure [sales]	Variable 25 to 45 psi
Bottom Hole temperature	?

Appendix 2

Attachment C in Original Proposal with Noted Modifications to Reflect Actual Expenditures by BEDCO

	Requested from SWC	Proposed Cost Share by BEDCO	Expended Cost Share by BEDCO
Salaries and Wages	$112,638	$224,675	$464,064
Fringe Benefits	--	--	--
Materials and Supplies	$7,400--	--	--
Equipment	$17,100	--	--
Travel	$30,560--	$2,170--	$2,400--
Publication/ Information Dissemination	--	$5,950--	$5,950--
Other direct Cost [Misc.	--	$3,250--	$4,010--
Prototype tools/ spares and modifications	$226,815-	--	--
		--	--
Facilities and Administration	$3,750--	$17,280--	$17,280--
Totals	$398,263-	$253,325— [39%]	$492,704— [55%]

Note: Total combined expenditures by SWC and BEDCO on the project are $890,967.00

Total Request from SWC	$398,263
Total Invoice by BEDCO	$389,792
Balance Returned to SWC	$ 8,497

TITLE PAGE

Report Title:
Plunger Conveyed Chemical System for Plunger Lift Wells

Type of Report:
Final Report

Reporting Period:
July 1, 2003 – December 31, 2004

Principal Author:
Sam Farris

Date Report Issued:
December 30, 2004

DOE Award Number:
2554-CE-DOE-1025

Submitting Organization Name and Address:
Composite Engineers, Inc.
129 Briarwood Street
Oklahoma City, OK 73160

DISCLAIMER

THE FINAL TECHNICAL REPORT

December 30, 2004
Composite Engineers, Inc.
Subcontract No. 2554-CE-DOE-1025

Lab tests on various non-metallic materials were selected and tested in an attempt to find suitable materials for use as plunger components. This effort was intended to identify materials that could perform adequately and still reduce abrasion caused by metal-to-metal contact during plunger travel in the absence of lubricants.
Lab tests conducted on the selected materials have some favorable and unfavorable results as noted in the attached data. Due to poor performance during the lab tests, some materials were omitted from the performance evaluations conducted in the test well. Wear data established by the test well paralleled the lab data for most samples. The samples containing glass performed far superior to all other samples in the test well. **Amodel®** samples suggested acceptable wear rates behind **Ryton®** samples. Documented expansion characteristics of **Amodel®** suggested performance improvement in certain well bore temperatures that enhanced expansion. Caution would be needed to prevent too much expansion in certain well conditions causing possible plunger sticking.

After studying the test well data and comparing it to the lab data, the producers of the wells to be used in the field trials were consulted, the test data was presented and a brush plunger design was selected. Composite wanted to be able to test non-metallic components for comparative analyses with the lab and test well data. Several plungers were modified to allow the installation of "wobble washer" components on the plungers run in the field trials.

Upon investigation of the tubing during well work, it was discovered the condition of the tubing string in the Doucet #1 was far from acceptable. The producer was not willing to replace the entire string of tubing. Instead, only the bottom 10 joints were replaced.

The wells changed ownership during the field trials. The new owners expressed a desire to add a foaming agent to be injected along with the corrosion inhibitor in the Doucet #1. The idea was to keep it unloaded better. Composite tested that application in the test well to determine if the foamed produced water adversely affects the plunger performance i.e, lift rates/plunger speed. No conclusive data could be generated with the test well only being 200' deep. No appreciable plunger speed difference could be determined and the re-circulation of the same produced water soon became saturated with the foaming agent.

Additional chemical pumps, tubing and connections were delivered to the Doucet #1 and installed. The chemical manufacturer didn't have any concerns with mixing the corrosion inhibitor and the foaming agent in the chemical chamber as the chemical pumps were timed to run in alternating cycles. Corrosion inhibitor volumes were maintained at 2-1/2 quarts per day and the foaming agent was adjusted to a rate of 1 quart per day.

The design modifications changing the ported segment of the plunger was completed. Four prototypes were produced. The modifications eliminated the ports completely and that eliminated the small cup that was required to block the ports in the plunger during the trip to the surface. This eliminated several machining operations and the part inside the plunger.

The difference in the specific gravity of the corrosion inhibitor and the produced water (being heavier) allowed the produced water to enter the plunger from the top and displace the lighter chemical. Observations in the lab suggested the flushing of the chemical from the plunger once it entered the fluid level at the bottom of the well had one negative effect. The negative change is that the chemical leaves the plunger at a slower rate than it did when the produced gas was allowed to "percolate" up, through the plunger, mixing the corrosion inhibitor as it displaced the chemical. The gas was observed mixing the chemical in the same manner as if it was flowing up, through the plunger. It just happened as the chemical was displaced out the top of the plunger. The agitation caused by the gas bubbles migrating up, past the plunger still allowed for complete dispersion of the chemical throughout the standing fluid level in the bottom of the well. The costs savings by eliminating the ports and "cup" in the bottom of the plunger could offset the additional costs to install a ball and seat valve mechanism in the base of the chemical chamber, another modification believed to improve the life of certain components.
Upon determining the application of the plunger without any ports, the specific gravity of the produced water will need to be a determining factor in the selection of plunger configuration. Costs to produce the non-ported plunger should also be a factor in plunger selection.

Honeywell has not shipped any more friction material since the copper impregnated samples. In a phone conversation with one of the engineers, the suggestion of shipping samples with high ceramic content probably will not happen. Poor performance of the samples tested, have caused Honeywell to re-think their involvement.

Work on pad segments produced from **Amodel** ® or **Ryton**® is moving slowly. Negotiations for injection molding of the pad segments are moving slowly. Pad segment design changes are being considered to help cut estimated production costs.

The data generated during the past 14 months is attached.

WEAR RATE COMPARISONS of NON-MATALLIC MATERIALS
LAB

Controls-Tubing samples positioned at 45°
Non-Metallic samples on ¾" x 6" long mandrel reciprocated 4" @ 20 SPM
Submerged in produced water @ ambient temperature
Duration- 1000 strokes

TUBING #1 before	931.8210 g	Amodel #1 before 75.5001 g		Amodel #1 after 74.0300 g
TUBING #1 after	930.7349 g			
TUBING #2 before	952.6590 g	Ryton #1 before 81.6143 g		Ryton #1 after 80.7431 g
TUBING #2 after	951.9347 g			
TUBING #3 before	977.9321 g	Ryton +25 before 81.5883 g		Ryton +25 after 80.9640 g
TUBING #3 after	966.0327 g			

TUBING #4 before	899.9348 g	Ryton+10 before 80.9440 g		Ryton+10 after 80.0313 g
TUBING #4 after	891.7342 g			
TUBING #5 before	902.7823 g	Poly #1 before 66.4312 g		Poly #1 after 61.0012 g
TUBING #5 after	902.0041 g			
TUBING #6 before	910.3497 g	HMWPE 89.4990 g		HMWPE 86.0133 g
TUBING #6 after	909.7594 g			
TUBING #7 before	970.4973 g	Honeywell #1 before 101.8349 g		Honeywell #1 after 81.9374 g
TUBING #7 after	969.7594 g			
TUBING #8 before	931.8210 g	Honeywell # 2 before 104.8323 g		Honeywell #2 after 87.2849 g
TUBING #8 after	930.7349 g			
TUBING #9 before	961.3310 g	Honeywell # 2 before 120.2573		Honeywell #2 after 97.2528 g
TUBING #9 after	959.4944 g			
TUBING #3 before*	966.0327 g	Honeywell # 3 before 107.8469		Honeywell #3 after 104.8465
TUBING #3 after *	965.9347 g			

Honeywell Sample #1- standard automotive brake pad materials
Honeywell Sample #2- Hi-temp automotive brake pad materials
Honeywell Sample #3- Formulated brake pad material containing copper
* This tubing sample was re-used to monitor brake pad material in a more favorable environment being,
a polished interior surface caused by testing Ryton + 25% glass.
The Honeywell Sample performed much better in the “conditioned” tubing.

FEP and Kevlar samples failed totally before any appreciable data could be established. That data is not included in this report since none of the samples survived the time/cylces established as an acceptable test period. Additional research indicated established plunger manufacturers’ commercialization of Teflon plunger components have limited success. As a result of these findings, Teflon was dropped as a possible component material for future tests.

WEAR RATE COMPARISONS of NON-MATALLIC MATERIALS
TEST WELL

	Before	After
Amodel #1	**45.9342 g**	**43.8394 g**
Amodel #2	**43.8493 g**	**41.8439 g**
Ryton #1	**46.8495 g**	**45.0342 g**
Ryton #2	**44.9401 g**	**43.1934 g**
Ryton +10 #1	**46.9485 g**	**45.7498 g**
Ryton +10 #2	**47.0023 g**	**44.4982 g**
Ryton +25 #1	**46.9934 g**	**46.4998 g**
Ryton +25 #2	**46.9832 g**	**46.0799 g**

All samples listed above were machined into rings or wobble washers and installed on a modified brush plunger. One ring was positioned immediately above the brush segment and one ring of like material was positioned immediately below the brush segment of the plunger.

Test well data suggests the Ryton®+25% glass samples performed best of those selected from the lab data. However, in review of the lab data, excessive metal loss was detected.
So, the Ryton®+10% glass was actually the best performer of the Ryton® group.

The Amodel® performed second best to the Ryton® group as far as comparitave material loss. Data gathered from dimentional investigations of the Amodel® samples re-inforced data gathered from other industry users. In that, when samples were exposed to produced water at slightly elevated temperatures (80° F+), the material expanded dimensionally.
Note: Material loss was within boundaries suggested by data from lab tests. Dimensionally, the material expanded to some degree even though the mass was reduced from appearant abrasion.

WEAR RATE COMPARISONS of NON-MATALLIC MATERIALS
FIELD TRIALS

	Before	Plunger Cycles	After
Amodel #1	45.4294 g	38	34.9345 g
Amodel #2	44.0993 g	32	39.5156 g
Ryton #1	45.9404 g	45	40.3042 g
Ryton #2	44.9401 g	34	41.1934 g
Ryton +10 #1	45.9874 g	51	35.6557 g
Ryton +10 #2	47.6101 g	35	44.4665 g

Ryton +25 #1	46.4581 g	47	36.4004 g
Ryton +25 #2	46.9832 g	24	45.3430 g

All samples #1 were tested in the Doucet #1 and samples #2 were tested in the Prejean #1. (the Doucet #1 had the tubing with the most advanced state of deterioration due to corrosion)

Samples tested in the field trials were difficult to compare due to the variables beyond control, the number of cycles in each respective well and the condition of the tubing strings of each well.

As plungers failed due to wear, the different materials were installed on replacement plungers.

All samples listed above were machined into rings or wobble washers and installed on a modified brush plunger. One ring was positioned immediately above the brush segment and one ring of like material was positioned immediately below the brush segment of the plunger.

Test well data suggests the Ryton®+25% glass samples performed best of those selected based on lab data. However, in review of the lab data, excessive metal loss was detected.
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Note: Material loss was within boundaries suggested by lab tests. Dimensionally, the material expanded to some degree even though the mass was reduced from appearant abrasion.

Upon completion of the wobble washer tests, the final modified plungers were installed in the 2 respective wells as brush only plungers, . Assuming the wobble washers run during the tests improved the interior finish of the tubing strings to some degree, the brush segments run during the final stages of the field trials suggested the wobble washers only had limited effect on retarding the brush segment wear of the early plungers run. Composite Engineers felt there were too many variables to come to any finite conclusions on “brush only” performance. Brush plunger performance has been proven time and again by the commercialization of the plunger design. During the field trials, the ownership of the two wells changed and the new owners allowed Composite to finish the tests. However, about 2 weeks prior to termination of the tests, a representative of the new owners attempted to adjust the controller on the Doucet #1 and caused the plunger to surface “dry” (without a column of water on top of the plunger). The extreme velocity of the plunger striking the lubircator severly damaged the chemical chamber and the plunger, requiring replacement. The standard plunger and lubricator cap were installed until Composite personnel could deliver replacement parts to the well site. The only plunger available at the time was a wobble washer type with all non-metallic washers of different materials. That plunger was installed and seemed to perform very well, even in the poor tubing condition. It ran for 13 days (# of cycles unknown) and was recovered with minimal wear. The top washer (Ryton®+10% glass) exhibited more wear than that of the lower washers. But, all were in very good condition.
The field trials were concluded with recovery of all Composite equipment.

CORROSION COUPON TEST RESULTS DURING FIELD TRIALS

Mild steel coupons were installed in the wellheads of 2 wells in South Louisiana to establish a base line for metal loss due to corrosion.

CORROSION COUPON # 34294 before initial installation in Doucet #1= 36.80625g
CORROSION COUPON # 34294 after 93 days service in Doucet #1= 30.43877g
Material loss based on chemical supplier's lab results= 17.3% 6.36748g

CORROSION COUPON # 34294 before initial installation in Prejean #1= 31.54938g
CORROSION COUPON # 34294 after 93 days service in Prejean #1 30.03501g
Material loss based on chemical supplier's lab results= 4.79% = 1.51437g

CORROSION COUPON TEST RESULTS DURING FIELD TRIALS

Mild steel coupons were installed in the wellheads of 2 wells in South Louisiana after deployment of chemical injector system to establish metal loss due to corrosion.

CORROSION COUPON # 34294 before second installation in Doucet #1= 30.43877g
CORROSION COUPON # 34294 after 93 days service in Doucet #1= 30.43877g
Material loss based on chemical supplier's lab results= 6.13% 1.86589g

CORROSION COUPON # 34294 before second installation in Prejean #1= 30.03501g
CORROSION COUPON # 34294 after 93 days service in Prejean #1 28.52064g
Material loss based on chemical supplier's lab results= 3.02% = 1.51437g

The addition of a foaming agent in the last 21 days of corrosion treatment in the Doucet #1 may have affected the results. Until another test is conducted, the findings will stay as determined for this report.

Understanding the entire system is fairly simple in design and has few moving parts. The field trials did not encounter any significant operational problems. The intended target of the research was to reduce corrosion damage to the tubular goods in the respective wells. The data suggests that goal was accomplished with resounding success. Composite Engineers, Inc. feels additional field trials of longer duration would offer additional information on performance capabilities of the system. Discussions with well operators in the Permian Basin, San Juan Basin, Rio Grande Valley and The Barnett Shale are ongoing. Some additional time will be needed to generate a viable supply of plungers to address all these possible applications. Additional efforts to incorporate a ball and seat sealing system for the chemical chamber is also being addressed.

This is the final report for DOE Grant # 2554-CE-DOE-1025 to the Stripper Well Consortium as of December 31, 2004.

Locating the End of Tubing for Efficient Production of Gas

Final Report

July 1, 2003

to

December 31, 2004

by

Richard L. Christiansen
John R. Fanchi

January 2005

Penn State Sub-Contract No. 2550-CSM-DOE-1025
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Disclaimer

Abstract

When initially completed, many natural gas wells are capable of lifting water and hydrocarbon liquids to the surface. But, with depletion of the reservoir pressure, there comes a time when liquids can no longer be lifted to the surface and they begin to accumulate in the bottom of the well, dramatically inhibiting or stopping gas production. A key factor for lifting liquids is the location of the end of the tubing in the casing relative to the various gas-bearing formations that have been completed. There is little agreement in the engineering community on the appropriate location for the EOT, or end of tubing.

The objective of this project was to develop technology and guidelines for properly locating the EOT for effective production of gas. Listed below are the two proposed tasks for this stage of the project:

Task 1: Directions for Model Development. Search the literature to assess available commercial software for solving the EOT problem. Begin conceptual development for numerical code specific to the problem.

Task 2: Flow-Loop Testing. Test various locations for the end of tubing in the flow-loop apparatus. Test variations of tubing design, including means for controlled inlet of gas at entry points above the tubing end.

Accomplishments for each of these tasks are summarized below.

Task 1: Directions for Model Development. The EOT problem and associated physical phenomena are described in terms of flow in pipes, and liquid loading. The state-of-the-art of relevant simulation technology in the industry is then assessed, and recommendations on how to model gas well production, deliquification, and associated EOT effects are presented.

Two options for developing a gas well model capable of modeling EOT effects are considered. The first option is to develop a fully coupled wellbore-reservoir model. The second option is to couple a wellbore model to a publicly available simulator. The first option is more accurate and is being pursued commercially, while the second option provides a public domain simulation system.

Task 2: Flow-Loop Testing. Flow-loop tests were performed to study the liquid-lifting rate at the junction of the tubing and casing. In these tests, the distance between the end of the tubing and the bottom of the casing was varied between1 and 5 feet. Liquid was charged to the bottom of the casing and gas flow rate was varied from about 50% to 120% of the critical flow rate for the tubing. In these tests, most of the liquid resided in a churning zone in the bottom 1 foot of the casing. The liquid production rate was measured for each gas flow rate. The liquid production rate was found to fall rapidly toward zero as the distance between the end of tubing and the bottom of the casing increased. It also fell rapidly with decreasing gas flow rate.

These end-of-tubing tests demonstrate that the tubing-casing junction is a bottleneck for liquid production from gas wells. To alleviate the bottleneck, it is apparent that a means for preventing liquid fall-back in the casing is needed. Three different devices were tested for boosting liquid production. The most successful of these was an assembly of rigid circular baffles. The baffles (cut from sheet metal) were mounted on a 3-foot-long slender rod. The space between baffles was 6 inches. The assembly was placed in the bottom of the casing below the end of the tubing. With the baffle assembly in place, the liquid production rate increased by a factor of 10 over a comparable test without the baffles.

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Introduction

The objective of this project is to develop technology and guidelines for properly locating the end-of-tubing (EOT) for effective production of gas. Removal of water and hydrocarbon liquids from gas wells is increasingly recognized as an important topic for low permeability gas reservoirs. A key factor is the location of the EOT in the casing relative to the various gas-bearing formations that have been completed. Figure 1 illustrates the system of interest. If not removed, liquids in the casing can decrease gas production rate. There is little agreement in the engineering community on the appropriate location for the EOT.

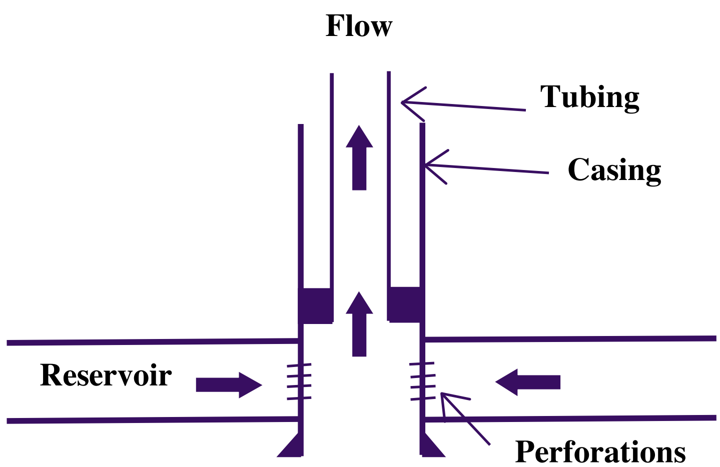

Figure 1. Illustration of End-of-tubing System

The purpose of this report is to present our assessment of the state-of-the-art of simulation methods that can be used to model EOT effects in gas wells, and to present results of flow-loop tests of liquid transport at the tubing-casing junction – the EOT.

In the following section, the approaches used for the two tasks this project are summarized. Then, the results of the two tasks are presented, followed by conclusions and recommendations for future work.

Description of Approaches

Task I: Directions for Model Development.

The state-of-the-art of simulator technology for studying end-of-tubing (EOT) effects in gas wells was determined using a conventional literature search and an informal survey of software vendors. The literature search provides information about studies that have been documented in the open literature. Several software development firms are interested in EOT effects, and a survey of software vendors provides some information about work that is being considered or underway at the time this report was written.

Task II: Flow-Loop Testing

The layout of the flow loop is shown in Figure 2. In brief, gas from the blower mixes with recycle liquid at the bottom of the loop, then the combined stream travels up inside the vertical test section, from which it is re-circulated to the gas-liquid separator. At the gas-liquid separator, the gas exits up to the blower, and the liquid exits down to the recycle pump. The vertical test section and portions of the recirculation lines are made of transparent PVC pipe to allow visual assessment of flow. The flow loop operates near ambient pressure and temperature.

For the end-of-tubing (EOT) tests, the vertical test section consisted of a 2-inch pipe mounted concentrically inside either a 4-inch or a 6-inch pipe as shown in Figure 2. The inner pipe ("tubing") was joined to the larger pipe ("casing") at the top with a rubber sleeve. This configuration was intended to represent the end of the tubing inside the casing of a gas well.

In the EOT tests, 1000 ml of water was charged to the bottom of the test section, gas was circulated at a set of flow rates, and the rate of water production to the separator was measured. The vertical position of the tubing was varied from about 2 feet to 6 feet above the lower end of the casing as noted in Figure 2.

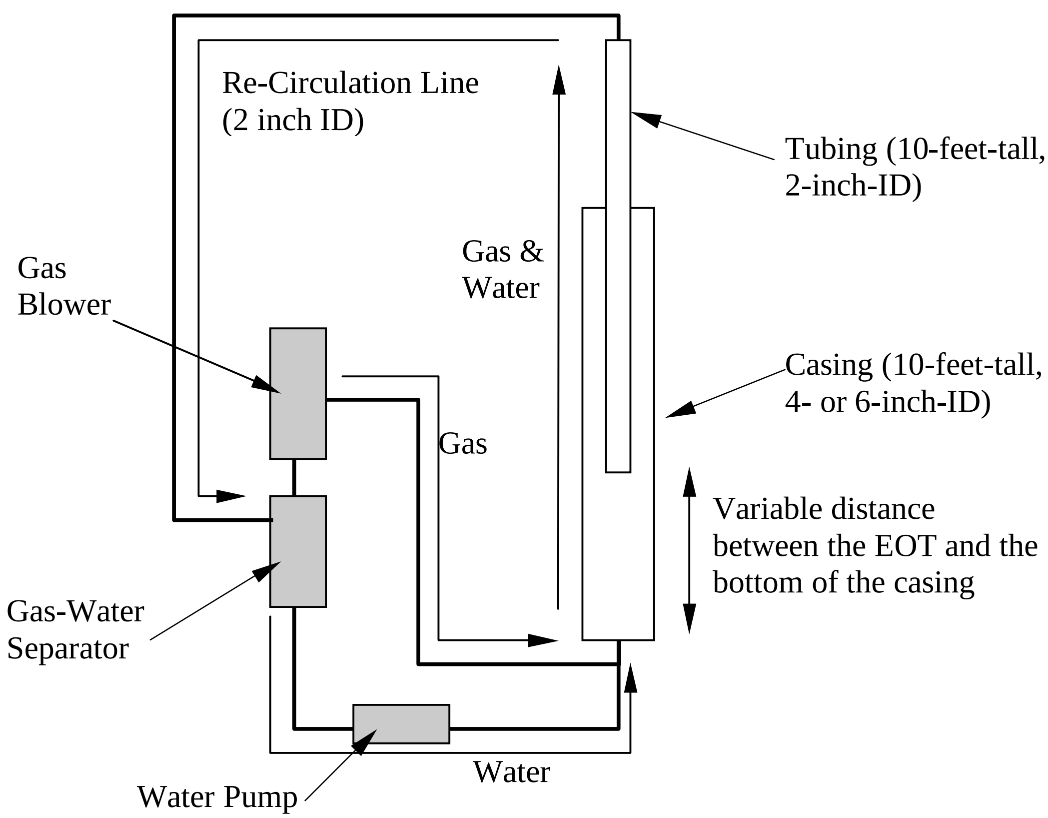

Figure 2. Schematic of Flow Loop.

After completing the EOT tests, a device was developed for increasing transport of water from the casing to the tubing. The device consists of circular sheets (all the same diameter) mounted on a slender rod (3 feet long) as shown in Figure 3. For the first tests of this device, the circles were cut from transparency film. For later tests, the circles were cut from sheet metal. The circles were spaced uniformly on the rod, 6 inches apart. The diameter of the circles was varied from 2 to 3.5 inches.

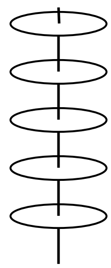

Figure 3. Baffle assembly for lifting liquid in casing.

After testing the above-described baffle assembly, a new implementation of "tubing collar inserts" was tested. We first tested tubing collar inserts 8 years ago (Yamamoto and Christiansen, 1999; Putra and Christiansen, 2001). Tubing collar inserts, as we defined them, provide a slight decrease in the inside diameter of the tubing as shown in Figure 4. We called them tubing collar inserts because we anticipated placing them in the tubing collars. Typically, the inside diameter of the insert is 0.13 to 0.50 inches less than the diameter of the tubing. Surprisingly, even a small diameter upset was found sufficient to prevent fallback of liquid on the walls. In the present tests, the insert was made by cutting a 0.13-inch-thick slice of a 2-inch PVC pipe, and then cutting a section from the slice as in Figure 5. This "split-ring" insert could be slipped inside the 2-inch tubing of the vertical test section by pinching it together. The split-ring insert could be placed easily at any position in the tubing.

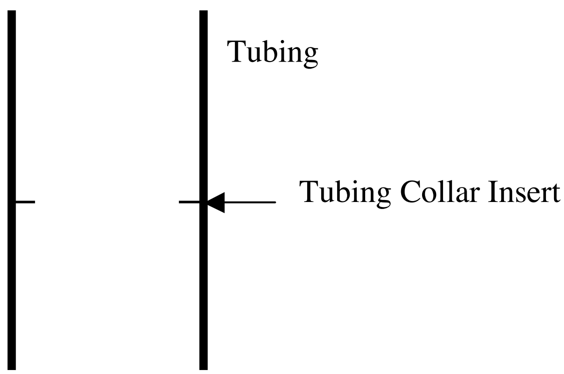

Figure 4. Tubing collar inserts

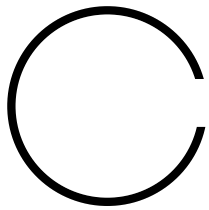

Figure 5. Split-ring insert, a new implementation of tubing-collar insert.

In addition to the above tests, a vortex inducing device was tested in the EOT flow loop. This device was made by cutting an ellipse with a rectangular tab from sheet metal with two cuts on the long axis as shown in Figure 6. Then, the two halves of the ellipse were twisted relative to each other to form an "X" if viewed from the side, with the tabs bent as shown on the right of Figure 6. This device was installed in a coupling that was placed at the bottom end of the tubing of the vertical test section. The tabs in the coupling gap prevented movement. This device proved to be a very simple approach for generating vortex flow.

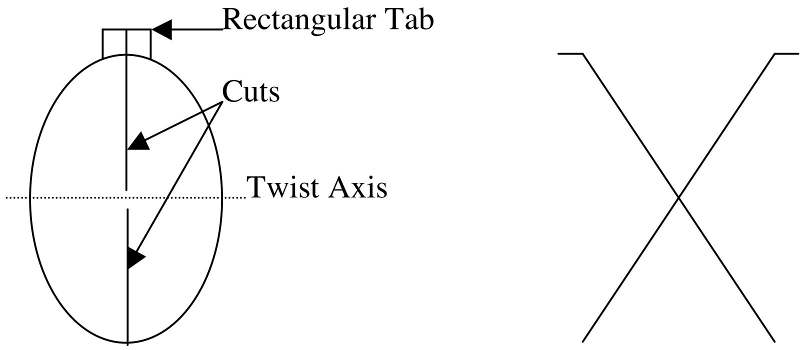

Figure 6. Vortex device. Left: Plan for cutting flat sheet. Right: Side view after twisting and bending the tabs.

Results and Discussion

Task I: Directions for Model Development

An appreciation of the state-of-the-art of simulation methods presumes a familiarity with the phenomenon being modeled. We begin with a description of the physical phenomenon, and then discuss simulation technology. The physical phenomenon of interest here is described in terms of two related phenomena: flow in pipes, and liquid loading. We then present a review of the state-of-the-art of relevant simulation technology that exists in the industry. We conclude with recommendations on how to model gas well production, deliquification, and associated EOT effects.

1. Fluid Flow in Pipes

The end-of-tubing (EOT) problem depends, in part, on fluid flow in pipes. We present a brief summary of factors that affect fluid flow in pipes. Approaches for modeling multiphase flow in pipes are reviewed in the next section.

Fluid flow in pipes can range from laminar to turbulent flow. Fluid does not move transverse to the direction of bulk flow in laminar fluid flow. By contrast, the velocity components of fluid flow fluctuate in all directions relative to the direction of bulk flow when fluid flow is turbulent. For a fluid with a given density and dynamic viscosity flowing in a tube of fixed diameter, the flow regime is laminar at low flow velocities and turbulent at high flow velocities. One parameter that is often used to characterize fluid flow is Reynolds number N_{Re}.

Reynolds number expresses the ratio of inertial (or momentum) forces to viscous forces. For fluid flow in a conduit, the Reynolds number is

$$N_{\mathrm{Re}} = \frac{\rho v D}{\mu} \tag{1}$$

where ρ is fluid density, v is bulk flow velocity, D is tube diameter for flow in a tube, and μ is the dynamic viscosity of the fluid. The choice of units must yield a dimensionless Reynolds number. In SI units, a dimensionless Reynolds number is obtained if fluid density is in kg/m^3, flow velocity is in m/s, tube diameter is in m, and dynamic viscosity is in Pa·s. Note that 1 cp = 1 mPa·s = 10^{-3} Pa·s.

We introduce the factors that influence fluid flow in pipe by considering the relatively simple case of single-phase flow in circular pipes [Beggs, 1991; Brill and Mukherjee, 1999]. We then discuss multiphase flow and end-of-tubing effects.

Single-Phase Flow in Pipes. Laminar flow along the longitudinal axis of a circular pipe is transverse to the cross-sectional area of the pipe. The cross-sectional area A of a circular pipe with internal radius r and internal diameter D is

$$A = \pi r^2 = \pi\left(\frac{D}{2}\right)^2 \tag{2}$$

The bulk flow velocity v of a single-phase fluid flowing in the circular pipe is related to volumetric flow rate q by

$$v = \frac{q}{A} = \frac{4q}{\pi D^2} \tag{3}$$

Reynolds number for flow in a circular pipe can be written in terms of volumetric flow rate by substituting Equation 3 into 1 to give

$$N_{\mathrm{Re}} = \frac{\rho v D}{\mu} = \frac{4\rho q}{\pi\mu D} \tag{4}$$

where ρ is fluid density and μ is the dynamic viscosity of the fluid. Fluid flow in circular pipes is laminar if $N_{\mathrm{Re}} < 2000$, and is considered turbulent at larger values of the Reynolds number.

The relationship between fluid flow velocity and pressure change along the longitudinal axis of the circular pipe is obtained by performing an energy balance calculation. The geometry of an inclined circular pipe with length L along the longitudinal axis and angle of inclination θ is shown in Figure 7. The single-phase fluid has density ρ and dynamic viscosity μ. It is flowing in a gravity field with acceleration g.

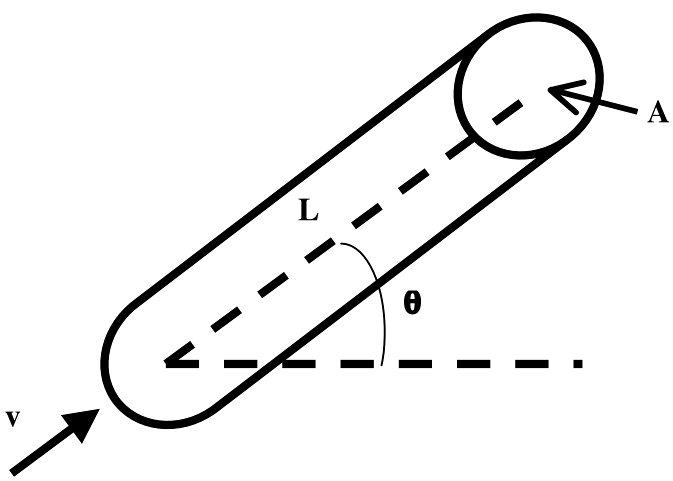

Figure 7. Flow in an inclined circular pipe

We make two simplifying assumptions in our analysis that allow us to minimize external factors and consider only mechanical energy terms. We assume no heat energy is added to the fluid, and we assume no work is done on the system by its surroundings, e.g. no mechanical devices such as pumps or compressors are adding energy to the system. An energy balance with these assumptions yields the pressure gradient equation

$$\frac{dP}{dL} = \left[\frac{dP}{dL}\right]_{PE} + \left[\frac{dP}{dL}\right]_{KE} + \left[\frac{dP}{dL}\right]_{\mathrm{fric}} \tag{5}$$

where P is pressure. We have written the pressure gradient along the longitudinal axis of the pipe as the sum of a potential energy term

$$\left[\frac{dP}{dL}\right]_{PE} = \rho\, g \sin\theta \tag{6}$$

a kinetic energy term

$$\left[\frac{dP}{dL}\right]_{KE} = \tilde{n}\, v \frac{dv}{dL} \tag{7}$$

and a friction term

$$\left[\frac{dP}{dL}\right]_{\text{fric}} = f\,\frac{\rho v^2}{2D} \tag{8}$$

that depends on a dimensionless friction factor f. If the flow velocity of the fluid does not change appreciably in the pipe, the kinetic energy term can be neglected and the pressure gradient equation reduces to the simpler form

$$\frac{dP}{dL} \approx \rho\, g \sin\theta + f\,\frac{\rho v^2}{2D} \tag{9}$$

Equation 9 is valid for single-phase, incompressible fluid flow. If we further assume that the right hand side is constant over the length L of the pipe, Equation 9 can be integrated to give the pressure change

$$\Delta P \approx \rho\, g\, L \sin\theta + f\,\frac{\rho v^2}{2D} L \tag{10}$$

The friction factor f depends on flow regime. For laminar flow with Reynolds number N_{Re} < 2000, the friction factor is inversely proportional to Reynolds number:

$$f = 16/N_{\text{Re}} \tag{11}$$

For turbulent flow, the friction factor depends on Reynolds number and pipe roughness. Pipe roughness can be quantified in terms of relative roughness ζ. Relative roughness is a fraction and is defined relative to the inner diameter of the pipe as

$$\zeta = \ell_p \big/ D < 1 \tag{12}$$

The length ℓ_p is the length of a protrusion from the pipe wall. Typical values of pipe relative roughness ζ range from 0.0001 (smooth) to 0.05 (rough). The length of protrusions inside the pipe may change during the period that the pipe is in service. For example, build-up of scale or pipe wall corrosion can change the relative roughness of the pipe. An estimate of friction factor for turbulent flow is [Beggs, 1991, page 61]

$$\frac{1}{\sqrt{f}} = 1.14 - 2\log\left[\zeta + \frac{21.25}{N_{\mathrm{Re}}^{0.9}}\right] \tag{13}$$

Multiphase Flow in Pipes. The description of single phase fluid flow in pipes presented above is relatively straightforward compared to multiphase flow. In particular, two-phase flow is characterized by the presence of flow regimes or flow patterns [see, for example, Griffith, 1984; Brill, 1987; Brill and Arirachakaran, 1992; Brill and Mukherjee, 1999; Lea, et al., 2003]. The flow pattern represents the physical distribution of gas and liquid phases in the flow conduit. Forces that influence the distribution of phases include buoyancy, turbulence, inertia and surface tension. The relative magnitude of these forces depends on flow rate, the diameter of the conduit, its inclination, and fluid properties of the flowing phases.

Flow regimes for vertical flow are usually represented by four flow regimes [Brill, 1987; and Brill and Mukherjee, 1999]: bubble flow, slug flow, churn flow, and annular flow. Churn flow and annular flow are referred to as slug-annular transition and annular-mist flow respectively by Lea, et al. [2003]. The four flow regimes are illustrated in Figure 8. Bubble flow is the movement of gas bubbles in a continuous liquid phase. Slug flow is the movement of slug units. Each slug unit consists of a gas pocket, a film of liquid surrounding the gas pocket that is moving downward relative to the gas pocket, and a liquid slug with distributed gas bubbles between two gas pockets. Churn flow is the chaotic movement of distorted gas pockets and liquid slugs. Annular flow is the upward movement of a continuous gas phase in the center of the conduit, an annular film of liquid flowing upward between the central gas phase and the wall of the conduit, and dispersed liquid droplets being lifted by the gas phase.

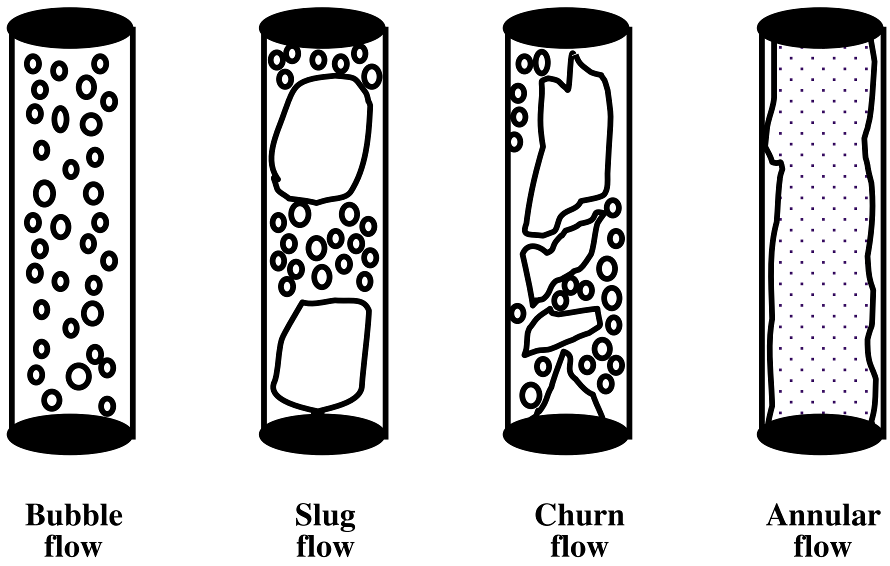

Figure 8. Flow regimes for vertical, two-phase flow (adapted from Brill and Mukherjee [1999, Figure 4.21])

Following Beggs and Brill [1973], Brill and Mukherjee [1999] represent multiphase flow in horizontal conduits using the seven flow regimes shown in Figure 9. These flow regimes are not universally accepted. For example, Brill and Arirachakaran [1992] used a similar set of flow regimes that were organized in terms of stratified flow, intermittent flow, annular flow, and dispersed bubble flow. More recently, Petalas and Aziz [2000] used the following set of flow regimes to represent multiphase flow in pipes: dispersed bubble flow, stratified flow, annular-mist flow, bubble flow, intermittent flow, and froth flow. Froth flow was described as a transition zone between dispersed bubble flow and annular-mist flow, and between annular-mist flow and slug flow.

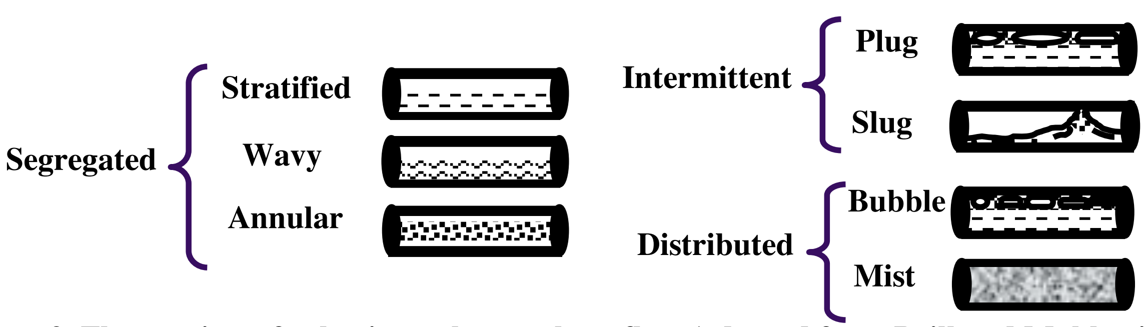

Figure 9. Flow regimes for horizontal, two-phase flow (adapted from Brill and Mukherjee [1999, Figure 4.16])

2. Modeling Multiphase Flow in Pipes

The identification of qualitative flow regimes discussed in Section 1 influences the structure of analytical and numerical models used to quantify multiphase flow in conduits. The flow regimes are used to construct flow regime maps, also called flow pattern maps, which are log-log plots of superficial gas velocity versus superficial liquid velocity. A flow pattern map is illustrated in Figure 10.

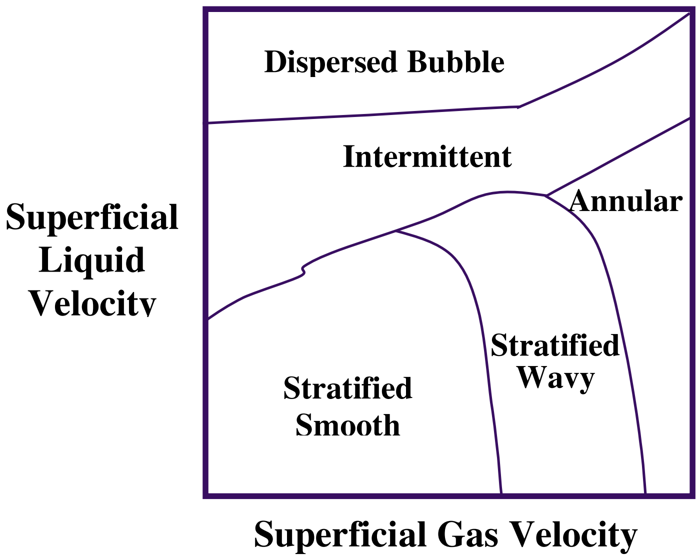

Figure 10. Illustration of a flow pattern map (adapted from Brill and Arirachakaran [1992, Figure 2])

Historically, predictions of multiphase flow in pipes began in the 1950's when investigators used data from laboratory test facilities and, to a lesser extent, field data to prepare empirical flow pattern maps [Brill, 1987; Brill and Arirachakaran, 1992]. Early models of multiphase flow were extrapolations of single phase flow models. Single phase terms in the pressure gradient equation introduced above were replaced with mixture variables. Thus, the terms in the pressure gradient equation for single phase flow given by Equation 5 become

$$\left[\frac{dP}{dL}\right]_{PE} = \rho_m \, g \, \sin\theta \tag{14}$$

for potential energy,

$$\left[\frac{dP}{dL}\right]_{KE} = \tilde{n}_m \, v_m \frac{dv_m}{dL} \tag{15}$$

for kinetic energy, and

$$\left[\frac{dP}{dL}\right]_{\text{fric}} = f\,\frac{\rho_m v_m^{\;2}}{2D} \tag{16}$$

for friction. The subscript m attached to variables on the right hand side of Equations 14 through 16 denotes that the associated variable is calculated for a mixture. Early models tended to neglect the kinetic energy term because the degree of turbulence of flow in wells at the time provided enough mixing of multiphase fluids to let the fluids be treated as homogeneous mixtures with gas and liquid phases moving at comparable velocities. Models based on mixture variables are called homogeneous models.

The decline in productivity of wells led to the need for more accurate multiphase flow models to represent phenomena such as gas slippage. In addition to homogeneous models, two other approaches are often used: empirical correlations, and mechanistic models. Empirical correlations depend on fitting experimental data and field data to models that contain groups of physical parameters. The empirical correlations approach can yield useful and accurate results quickly, but does not provide a scientific basis for extrapolation to significantly different systems. By contrast, mechanistic models are based on physical mechanisms that describe all significant flow mechanisms. Modern mechanistic modeling still requires some empiricism to determine poorly known or difficult to measure parameters [Brill and Mukherjee, 1999].

Shi, et al. [2003] observed that mechanistic models are the most accurate models, but are not well suited because they can exhibit discontinuities in pressure drop and holdup at the transition between some flow patterns. One way to solve this problem is to use a drift-flux model. The basic drift-flux model was introduced by Zuber and Findlay [1965]. Drift-flux models are modifications of the homogeneous models described above. From the perspective of reservoir simulation, homogeneous models have the advantages that they are relatively simple, continuous, and differentiable. A significant disadvantage of homogeneous models is that they do not account for slip between fluid phases. Drift-flux models are designed to resolve this deficiency, as well as model counter-current flow. Counter-current flow is the movement of heavy and light phases in opposite directions when there is no net fluid flow in the conduit or the fluid flow is slow. Drift-flux models are used in many reservoir simulators, such as the multi-segment well model in ECLIPSE® black oil and compositional reservoir simulators [Holmes, et al., 1998].

3. Liquid Loading and End-of-Tubing

Sections 1 and 2 discussed flow in pipes as one aspect of the physical phenomenon of interest here. In this section, we discuss the concept of liquid loading in gas wells. We first define liquid loading and identify some deliquification techniques to establish a context for understanding the end-of-tubing (EOT) problem.

Liquid Loading. Few gas wells produce dry gas only. Gas wells often produce varying amounts of water depending on reservoir performance and production operations. For example, high flow rate gas wells are able to carry liquids to the surface. If the gas rate decreases due to reservoir pressure depletion, or the volume of liquid entering the wellbore increases relative to the volume of gas, all of the liquid in the wellbore will not be produced and will begin to accumulate in the base of the well. As another example, gas production from water-drive gas reservoirs can result in water coning and liquid accumulation in the wellbore. The accumulation of liquids in the wellbore is liquid loading.

Liquid loading adversely affects gas well productivity because it results in an increase in flowing bottom-hole pressure and an eventual decrease in gas rate. Turner, et al. [1969] conducted one of the first and most extensive investigations to determine the minimum gas rate that would provide continuous removal of liquids. If enough liquid accumulates in the wellbore, the well may be unable to flow and productivity will be completely lost.

Deliquification Techniques. Removal of water and hydrocarbon liquids from gas wells is increasingly recognized as an important topic for maintaining gas well productivity. Several techniques have been developed to deliquify gas wells. Lea, et al. [2003], and Lea and Nickens [2004] discuss several deliquification techniques. These techniques include management of well flow rate, reducing the size of tubing, installing downhole pumps such as electric submersible pumps, installing downhole separators, installing surface pumps, implementing plunger lift, etc. It is often necessary to combine techniques. For example, Aguilera, et al. [2003] used water production wells and gas lift to dewater a naturally fractured reservoir in Argentina and increase gas production.

End-of-Tubing. The location of the EOT in the casing relative to the various gas-bearing formations that have been completed can be used to minimize the affect of liquid loading on gas well productivity. Some researchers have attempted to develop guidelines for setting the EOT. We consider two examples here.

As our first example, we note that Lea, et al. [2003] suggested that the EOT should be set at the top third of the pay interval. They argue that the EOT should not be set below the top third of pay so that liquid accumulating in the wellbore will not cover perforations during well shut-in. On the other hand, they say that the EOT could be set below the top third of the pay zone if the operator knows the perforations are open below the EOT.

It is interesting to contrast the above example with the study by McMullan and Bassiouni [2000]. They used a reservoir simulator to study the impact of the location and length of the perforated interval on ultimate gas and water recovery from a water-drive gas reservoir. The model consisted of a gas zone sitting atop a water zone with properties typical of reservoirs in the Gulf of Mexico. The reservoir simulator included coupling between flow from the reservoir into a well, and a wellbore hydraulics model for flow in the wellbore. Cases were run with the perforated interval in the top half of the gas zone, a perforated interval in the top tenth of the gas zone, and a perforated interval that was completed throughout the gas zone. They found that the length of the perforated interval did not significantly affect ultimate gas recovery, but did affect ultimate water recovery for their gas-water system. These results were sensitive to reservoir and aquifer permeability.

The above examples demonstrate the complexity of the EOT problem and show that it is difficulty to establish general guidelines. Many attempts have been made to model the problem. They are discussed next.

4. State-of-the-Art of Simulator Technology

The state-of-the-art of simulator technology for studying end-of-tubing (EOT) effects in gas wells was determined using a conventional literature search and an informal survey of software vendors. Interest in EOT effects in gas wells has increased as the demand for natural gas has increased. In addition to conventional sources of natural gas, unconventional sources such as tight gas sands and methane from coal seams are being developed. End-of-tubing effects can have a significant, adverse impact on gas well productivity. The literature search provides information about studies that have been documented in the open literature. Several software development firms are interested in EOT effects, and a survey of software vendors provides some information about work that is being considered or underway at the time this report was written. We discuss both the literature search and the vendor survey below. Both surveys rely on wellbore-reservoir coupling, which we now consider.

Wellbore-Reservoir Coupling. We have seen in previous sections that many factors affect multiphase flow in wells. Most of the discussion thus far has focused on wellbore modeling of multiphase flow. These models represent outflow from the wellbore-reservoir system shown in Figure 1. We must also consider inflow into the wellbore.

Wellbore inflow represents fluid flow from the reservoir into the wellbore. Reservoir fluid flow may be modeled using either analytical methods or numerical methods. Analytical methods rely on models of inflow performance relationships (IPR) that were first proposed by Gilbert [1954]. An IPR is the functional relationship between reservoir production rate and bottomhole flowing pressure. Darcy's law is a simple example of an IPR for single phase liquid flow. The gas well backpressure equation is an example of an IPR for single phase gas flow. Vogel [1968] introduced an IPR for the oil rate from a two-phase reservoir. Vogel's IPR depended on absolute open flow potential, which is the flow rate that is obtained when the bottomhole flowing pressure is equal to atmospheric pressure. Fetkovich [1973] proposed a variation of Vogel's model that does a better job of matching field data from producing oil and gas wells. Joshi [1988] proposed an IPR for horizontal wells.

Figure 11 illustrates the relationship between an IPR curve and a Tubing Performance Curve (TPC). It is a plot of fluid flow rate Q_{fluid} versus bottomhole flowing pressure P_{wf}. Reservoir pressure P_{res} is the pressure at $Q_{fluid} = 0$. The intersection of the IPR and TPC curves identifies the flow rate and bottomhole flowing pressure that simultaneously satisfy inflow into the wellbore from the reservoir and outflow from the wellbore.

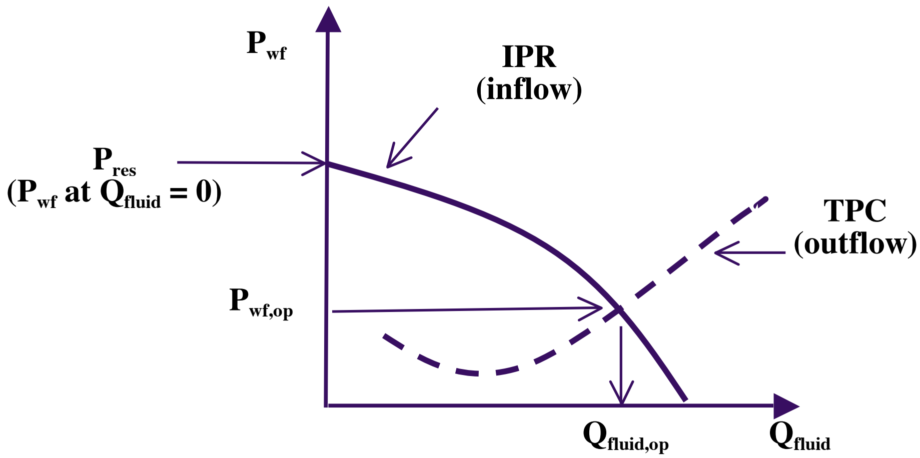

Figure 11. Illustration of an IPR versus TPC Plot

The IPRs described above are examples of analytical representations of fluid flow into a wellbore. Another way to calculate inflow into a wellbore is reservoir simulation. Commercial reservoir simulators typically allow the user to specify tubing curves that relate surface pressure to bottomhole flowing pressure. Williamson and Chappelear [1981] reviewed the traditional representation of wells in reservoir simulators. More recent discussions of well models in reservoir simulators are presented by Ertekin, et al. [2001], Holmes [2001], and Mlacnik and Heinemann [2003].

Tubing curves in reservoir simulators allow the user to specify wellhead pressures and then calculate bottomhole flowing pressures. The tubing curves are typically from empirical correlations, mechanistic models, or drift-flux models. Modelers have found that more sophisticated wellbore models are needed to represent time-dependent (transient) effects in the wellbore. Modern wellbore models are using partial differential equations based on conservation of mass and energy that must be solved numerically in much the same way as flow equations in reservoir simulators. An illustration of a gridding scheme for a coupled wellbore-reservoir system is shown in Figure 12. Gridding schemes for modeling advanced wells are discussed by Mlacnik and Heinemann [2003], and Holmes [2001].

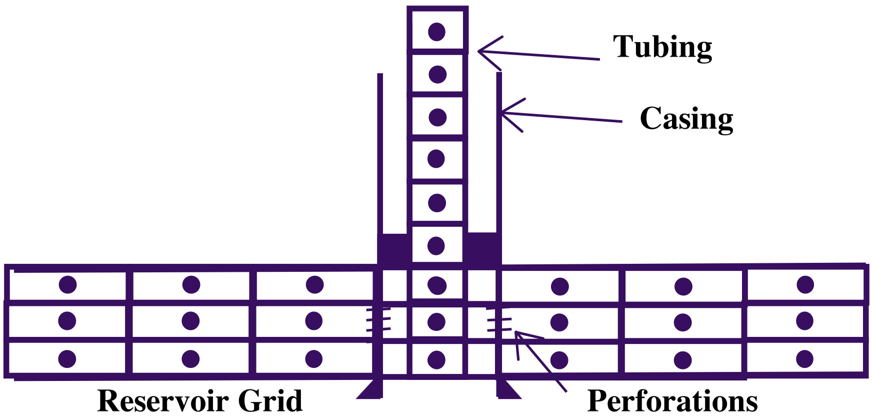

Figure 12. Schematic of a Coupled Wellbore-Reservoir Grid

The degree of coupling of the wellbore model to the reservoir simulator can be used to classify wellbore-reservoir simulators. The coupling may be sequential or implicit. Sequential coupling solves the wellbore model after the reservoir flow calculation is complete. Implicit coupling simultaneously solves the wellbore and reservoir models. Settari and Aziz [1974] used a coupled reservoir-wellbore simulator to study two-phase coning problems. Winterfeld [1989] introduced a formulation that rigorously coupled a reservoir model with a model of multiphase flow in a wellbore to evaluate pressure transient tests. Stone, et al. [1989] developed a coupled reservoir-wellbore simulator that was able to model transient, thermally dependent, three-phase flow (dead oil – water – gas) in the wellbore.

Beginning with Dempsey [1971], some simulators have been designed to couple wellbore and surface facility models to the reservoir model. Dempsey, et al. [1971] developed a simulator that coupled reservoir and surface facilities to study gas-water systems. More recently, Litvak and Darlow [1995] coupled a wellbore model to a compositional simulator that was later used to study the performance of Prudhoe Bay [Litvak, et al., 1997]. Coats, et al., [2004] formulated a black oil – compositional model that was fully coupled to wellbore and surface facility models.

Industry Survey. A select group of companies was identified and queried about their ability to simulate gas well dewatering. The companies were selected based on their experience in reservoir simulator development. The survey pointed out that the removal of water and hydrocarbon liquids from gas wells is increasingly recognized as an important topic for producing gas reservoirs. A key factor is the location of the end-of-tubing (EOT) in the casing relative to the various gas-bearing formations that have been completed. If not removed, liquids in the casing will adversely affect gas production. For example, the back pressure of accumulated water on the perforations will decrease production rate. Another adverse effect is the formation of a water block by the back flow of water from the casing through the perforations to the gas-bearing formations.

The survey sought simulators that could model the effects of water accumulation in a gas well. Simulators were expected to couple a reservoir model with a wellbore model. Water should be soluble in the gas phase. The wellbore model should be able to model mass transfer between phases as fluid flows from reservoir conditions to surface conditions. This implies a dependence on both pressure and temperature. Given this background, we asked companies if they had any software that could meet these needs.

Survey responses showed three widely used, practical modeling approaches that could be used to approximate EOT effects. The approaches are summarized in Table 1. Several commercial reservoir simulators are examples of Approach 1. They include such simulators as ECLIPSE by Schlumberger, GEM by Computer Modeling Group, VIP by Landmark Graphics, and SURESim by Seismic Micro-Technology.

Table 1: Practical Modeling Approaches

Approach	Comment
1	Sophisticated reservoir simulator with production tubing curves
2	Sophisticated wellbore simulator with inflow performance relationship
3	Coupled wellbore-reservoir simulator

An example of Approach 2 is the wellbore simulator OLGA [Bendiksen, et al., 1991]. OLGA is a mechanistic, multiphase, transient pipe flow model. It has been used recently to study such effects as gas lift well instability [Hu and Golan, 2003] and transient flow conditions associated with electric submersible pumps in wells with sinusoidal profiles [Noonan, et al., 2003]. It has limited IPR capabilities, however it is possible to sequentially couple OLGA with a reservoir simulator.

A commercial example for Approach 3 is the thermal simulator STARS coupled to the Discretized Well Model (DWM) by Computer Modeling Group. Another example is the proprietary simulator Gensim by EnCana [Edmunds, 2004; Stone, et al., 1989]. The latter simulator uses a drift flux model for transient, multiphase flow in pipes. It was used for modeling such complex phenomena as geothermal effects in thermal production rises [Edmunds and Good, 1996].

5. Directions for Model Development

The transient nature of liquid loading and end-of-tubing (EOT) effects significantly adds to the difficulty of modeling EOT effects. The first two modeling approaches in Table 1 are not as general as Approach 3, which relies on wellbore-reservoir coupling. Two options for developing a gas well model capable of modeling end-of-tubing (EOT) effects are described here.

Option I

The most accurate technique for modeling EOT effects is to use a fully coupled wellbore-reservoir simulator. The wellbore model should be based on a drift flux technique to handle transient wellbore effects, and the reservoir simulator should be fully implicit to represent near wellbore fluid and pressure changes. Efforts to develop fully coupled wellbore-reservoir simulators have been documented in the literature and the technology is being commercialized. Examples of Option I simulators and associated references are discussed in the previous section.

Option II

Option I is the most sophisticated approach to modeling EOT effects. A less sophisticated technique for modeling EOT effects that can provide a more publicly available simulation system in a shorter period of time would be to modify existing public domain software. The United States Department of Energy presently provides the public access to the three-phase, three dimensional simulators BOAST and MASTER [NPTO, 2004].

BOAST and MASTER are implicit pressure-explicit saturation (IMPES) simulators. The formulation in MASTER is mass conserving, while BOAST does not include a mass conserving expansion of the accumulation term [Fanchi, 1986]. On the other hand, the MASTER formulation requires very small time steps (a few days), while longer time steps are possible with BOAST. The lack of a mass conserving expansion in BOAST is a problem primarily when phase transitions occur, such as moving from single phase oil to two-phase gas and oil. One or both of these publicly available simulators could be modified to include a transient wellbore model. To minimize run-time requirements, the transient wellbore model should be based on a drift flux model.

Task II: Flow-Loop Testing

As explained above in **Description of Approaches**, the first flow loop tests explored the effect of vertical position of the end of tubing (EOT) relative to the bottom of the larger pipe ("casing") in the vertical test section. Figure 6 shows results for the tubing in the 4-inch ID casing with the EOT 5 feet above the bottom of the casing. The very important result is that the water-lifting rate below the critical flow rate is extremely small, mostly less than 0.10 bbl/day. The estimated critical flow rate in the figure is for the tubing (not the casing) using the Turner-Hubbard-Dukler (1969) or THD correlation without the 20% increase, as suggested by Coleman *et al*. in 1991. Figure 7 shows results for the EOT 2 feet above the bottom of the casing. In this case, the liquid flow rate is significantly higher, approaching 1 bbl/day for the 4-inch casing at the critical flow rate. For the 6-inch casing, the maximum liquid flow rate is less than 0.4 bbl/day. Composite results for the 4-inch casing are shown in Figure 8. Liquid flow rates as high as 4 bbl/day were observed when the EOT was just 1 foot above the bottom of the casing. In all of these tests, the bulk of the liquid resided in a zone of churning flow regime less than 1 foot tall at the bottom of the casing. At 1 foot above the bottom, the EOT was just above this churning zone. (The height of the churning zone was between 0.5 and 1.0 feet for all flow rates tested.)

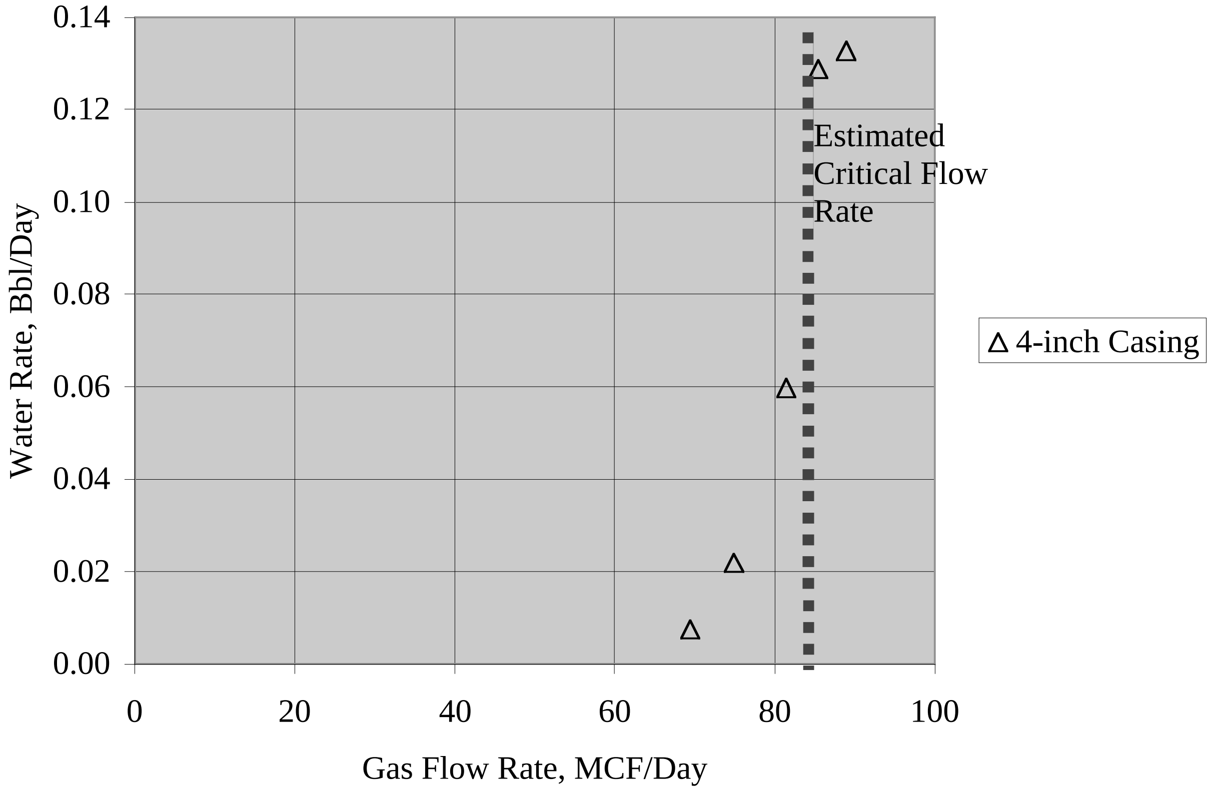

Figure 6. Liquid production for the EOT 5 feet above the bottom of the 4-inch casing.

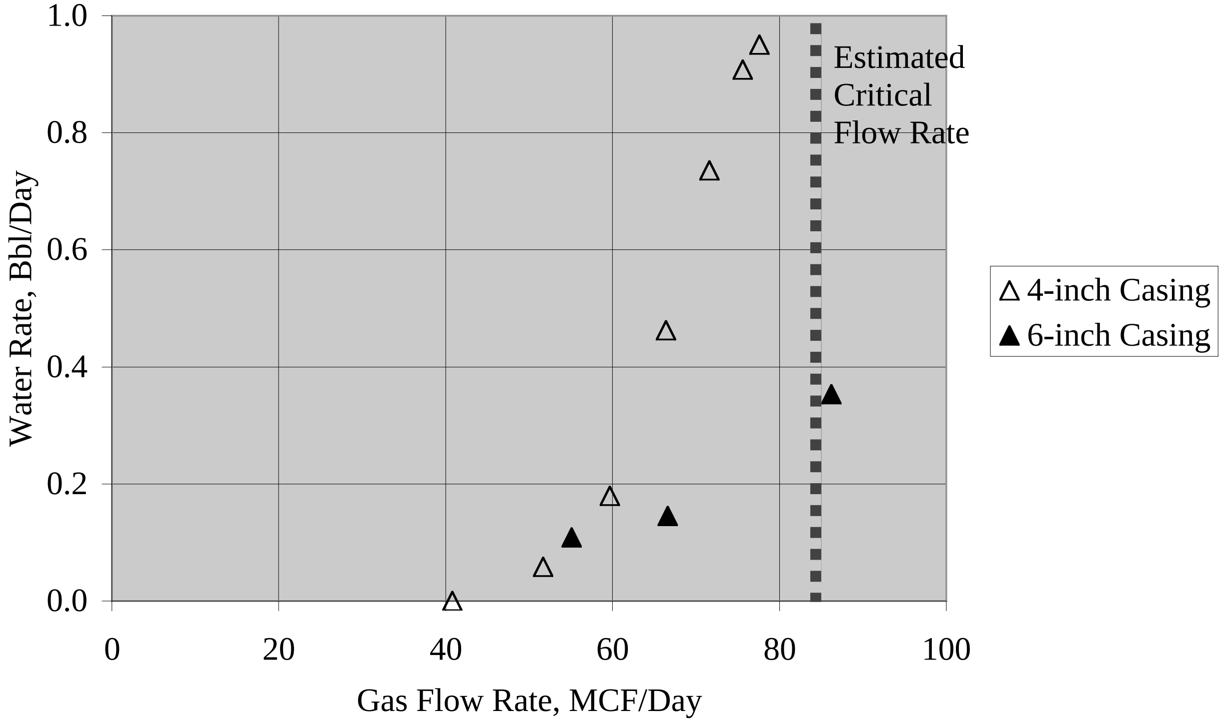

Figure 7. Liquid production for the EOT 2 feet above the bottom of the casing.

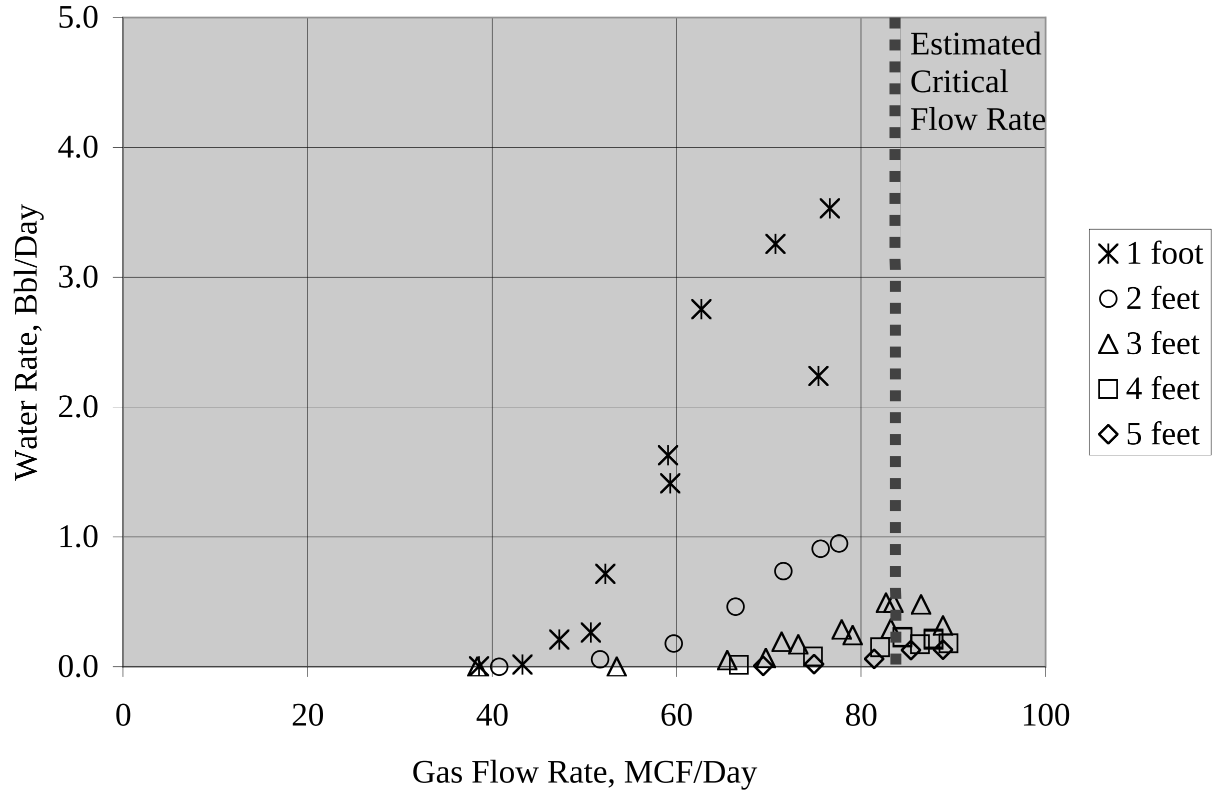

Figure 8. Liquid production for the EOT 1 to 5 feet above the bottom of the 4-inch casing.

The results of Figure 8 show that liquid lifting rate for a tubing-casing system is dominated by liquid transport at the tubing-casing junction. As separation increases between the churning zone in the casing and the EOT, the liquid transport rate rapidly falls toward zero. These results agree with down-hole video observations at the tubing-casing junction that were collected by Centrilift while testing well-bore heating for preventing liquid loading. In that video, the end of the tubing was essentially dry even though a zone of churning liquid was just 10 feet below.

After recognizing the rapid loss of liquid transport rate at the tubing-casing junction, a number of ideas were considered for improving the transport rate. The uniting philosophy of these ideas is prevention of liquid "fall-back." Liquid fall-back is a characteristic feature of churning flow in which most of the liquid that is blown upward in a pipe by the gas stream falls back down the pipe. In previous work (Yamamoto and Christiansen, 1999; Putra and Christiansen, 2001), we found that tubing-collar inserts could prevent liquid fall-back in tubing, so a similar approach was chosen. The ideas rapidly evolved to the baffle assembly of Figure 2. In the first tests of the baffle assembly, the baffles were cut from transparency film, which is quite flexible. While some of the liquid transport results were promising, they were not reproducible. The reason for the lack of reproducibility was thought to be flexibility of the baffles. In some tests, the baffles remained largely flat, while the baffles curled in others. To test this hypothesis, rigid baffles were cut from sheet metal. The results for these tests are summarized in Figure 9.

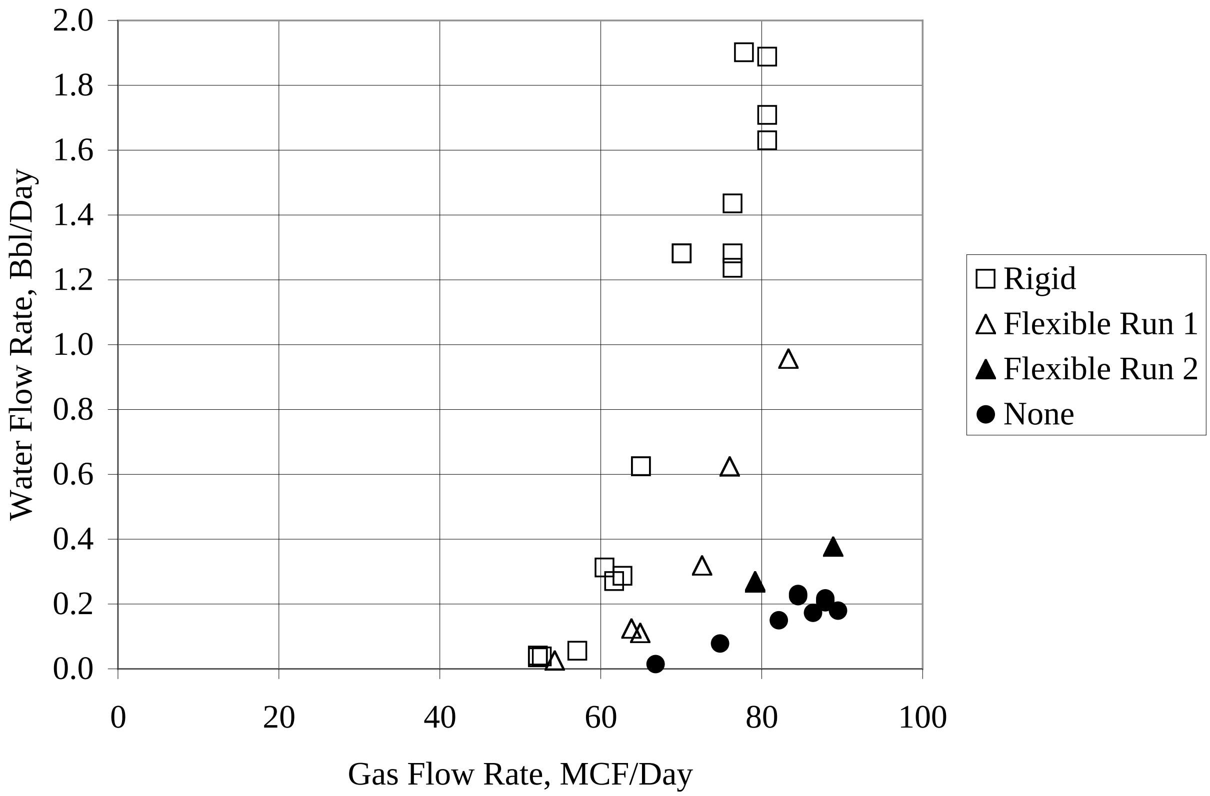

Figure 9. Comparison of performance of 3-inch-diameter rigid and flexible baffle assemblies with EOT 4 feet above the bottom of 4-inch casing.

Figure 9 shows four things. First, liquid-lifting rate for the rigid baffles is 10 times that when no baffles are used. Second, the rigid baffles perform significantly better than the flexible baffles. Third, performance of the flexible baffles is quite variable, as noted before. And fourth, even with the rigid baffle assembly, the liquid lifting rate falls rapidly as gas flow rate declines.

A number of design issues remain for baffle assemblies. The first of these is probably optimum baffle diameter and spacing. Liquid lifting performance for 2-inch-diameter rigid baffles in 4-inch casing was much poorer than the 3-inch baffles and was not measured. In tests with 3.5-inch-diameter baffles, the baffles were levitated by the flow stream – so lifting rates were not measured. The effect of baffle spacing was not explored at all. Another issue that should be explored is the performance of baffles that are rigid near their centers and flexible away from the center. Assemblies of such baffles might be able to slip down the tubing of a well while still providing performance equal to rigid baffle assemblies.

In addition to the baffle assemblies, two other ideas were tested to boost liquid transport at the tubing casing junction: split-ring inserts (Figure 4) and a vortex device (Figure 5). Neither of these ideas proved beneficial. Results for the vortex-inducing device are shown in Figure 10. There, the difference in liquid-lifting rate with and without a vortex-inducing device is insignificant. Although the split-ring inserts did not increase the liquid transport rate at the tubing-casing junction, they may prove useful for lifting in the tubing. Their design may be suitable for placement with a wireline tool.

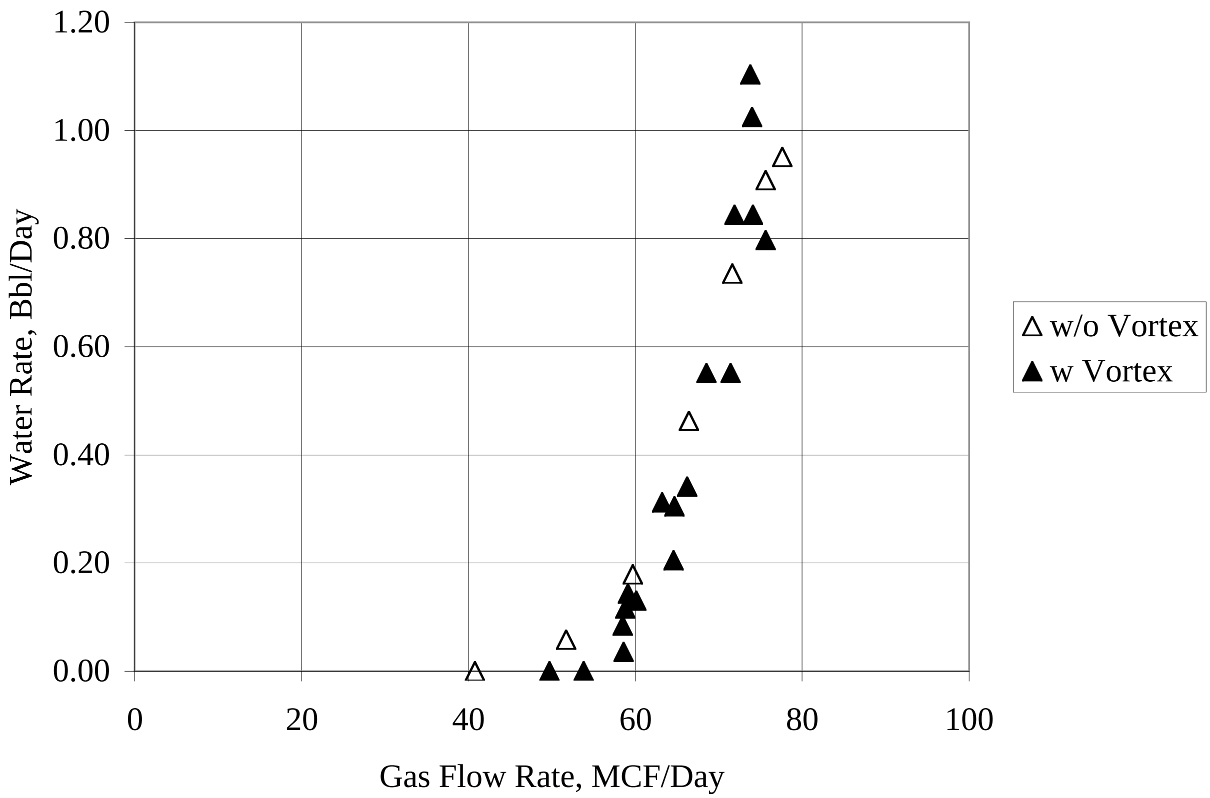

Figure 10. Comparison of liquid lifting rate with and without a vortex-inducing device.

Conclusions

1. An industry survey revealed three widely used, practical modeling approaches that could be used to approximate EOT effects. (See Table 1.)
2. The most accurate technique for modeling EOT effects is to use a fully coupled wellbore-reservoir simulator. The wellbore model should be based on a drift flux technique to handle transient wellbore effects, and the reservoir simulator should be fully implicit to represent near wellbore fluid and pressure changes.
3. Efforts to develop fully coupled wellbore-reservoir simulators have been documented in the literature and the technology is being commercialized.
4. Publicly accessible reservoir models (BOAST and MASTER) could be modified to include a transient wellbore model. The transient wellbore model should be based on a drift flux model.
5. Lifting of liquids is severely impaired by the tubing-casing junction – the end-of-tubing (EOT). Tests in the flow loop showed that the liquid transport rate through the EOT rapidly falls to less than 0.1 bbl/day as the separation between the EOT and the gas-liquid contact in the casing increases to just 5 feet.
6. The rate of liquid transport through the EOT depends on gas velocity and distance between the EOT and the gas-liquid contact in the casing.
7. Several ideas were tested in the flow loop for increasing liquid transport through the EOT. Of these, a system of baffles below the EOT was most successful. Development of baffle systems should be a priority for future SWC funding.
8. A device that induced vortex flow in the tubing above the EOT did not alter the liquid transport rate. Similar results were found for tubing inserts.

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Chamber Lift – A Technology For Producing Stripper Oil Wells – Stage II

during the Period 7/1/2003 to 12/31/2004

By

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DISCLAIMER

ABSTRACT

The largest expense associated with operation of most stripper oil wells and many stripper gas wells are the lifting costs associated with the removal of fluids from the well bore. The predominate artificial lift method used is rod pumping. Much of the existing equipment is oversized, outdated and the maintenance costs required to keep this equipment operational are large and continue to increase. One option for replacing rod pumping, is to use an intermittent gas chamber lift system. The gas chamber lift system reported here is specifically being developed as a fluid lift system for low volume wells. The system uses newer types of materials for tubulars to minimize capital costs and reduce maintenance associated with corrosion and mechanical wear. Other advantages of the system include: easy conversion from a rod-pumping system; minimal mechanical and electrical equipment at the well-site; fewer down-hole moving parts; and less labor intensive procedures for repair

Bretagne GP, an independent producer, teamed up with Penn State University and made a proposal to design and field test a chamber gas lift system. An initial study was performed with a lab scale model at Penn State and a field test of a well equipped with a prototype of the "chamber-lift system." The current study focuses on field testing of the concept. Two wells have been equipped with the chamber lift system. Different completion methods have been utilized, such that testing of the system using different operating conditions can be performed. The chamber-lift system has been successfully operated using a conventional surface controller. Moreover, the surface controller was actuated using electrical power generated at the well-site using a solar panel.

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1.0 Introduction

Project Background

The typical stripper oil well in the United States produces only a few barrels of crude oil per day. Most domestic stripper wells are operated by independents rather than by large integrated oil companies. The fundamental challenge at hand is determining the most economical method to operate these wells in order to lift the crude oil from the well-bore, to the tank batteries. It is this lifting cost that is the single largest expense attendant to the operation of these stripper wells. There are currently many different technical approaches to lifting liquids from the well-bore. These include: Beam pumps, plunger lift, gas lift, electric-submersible pumps. The most common method currently used is the beam pump that is shown in Figure 1. However, beam pumps have several drawbacks. It could be argued that the largest drawback is the maintenance cost attendant to keeping

Figure 1. Typical Beam Pump

beam pumps continuously operating. Clearly an option to the use of beam-pumps is desirable. To this end, Bretagne G.P. and the Pennsylvania State University collaborated in an investigation that was funded by the Stripper Well Consortium (SWC) during 2001. The approach utilized was to improve and modify existing gas lift technology for use in stripper wells by independent-operators. The primary goal of the original study was to optimize the gas lift system by building a laboratory scale model at Penn State. Experience gained through testing with the lab scale model was then implemented into a full scale field test on an existing well operated by Bretagne G.P. in the Big Sinking Field located in eastern Kentucky.

Lab Scale Model

During the previous phase of the current project, a working laboratory scale model of an intermittent gas lift system was designed and constructed at Penn State. This work was carried out by a graduate student whom used this research as the basis for his PNG Masters Thesis[1]. The basic geometry of this system was two concentric strings of steel pipe. The outer string was constructed of 2 inch steel pipe with an inter string of 1 inch steel pipe. This system was operated by injecting the lift gas down the annulus space created between the 2 inch and the 1 inch pipe. Fluid was then produced up the 1 inch pipe. An adjustable back pressure regulator was placed at the outlet of the fluid siphon string to replicate the friction and fluid head encountered in the full scale system in the field. Figure 2. shows this experimental setup at Penn State. The overall height of the system is approximately 20 feet.

The reservoir was replicated by a large pressurized tank filled with fluid. (gray tank in Figure 2) This tank was pressurized with compressed air and the pressure was a variable in the test matrix that replicated the reservoir pressure in the actual field. A standing valve was placed at the bottom of the outside string allowing fluid to enter the chamber and rise to a level where the fluid head was equalized with the reservoir pressure. (Pressure in the gray tank) When a lift was initiated by sending compressed air down the annulus between the strings of pipe, the standing valve would close and prevent fluid from returning into the reservoir. The fluid would then be forced up the 1 inch dip tube and to the "surface". The lift system was instrumented with pressure transducers, (static and differential), a thermocouple, and liquid and gas flow meters. This data were then recorded using a laptop equipped with LabView data acquisition software. A test matrix was setup by varying the composition of a mixture of mineral oil and water as the fluid being lifted. The gas injection pressure and the reservoir pressure were the other two variables in the test matrix. Later testing was performed with crude oil from the same field as the full scale test.

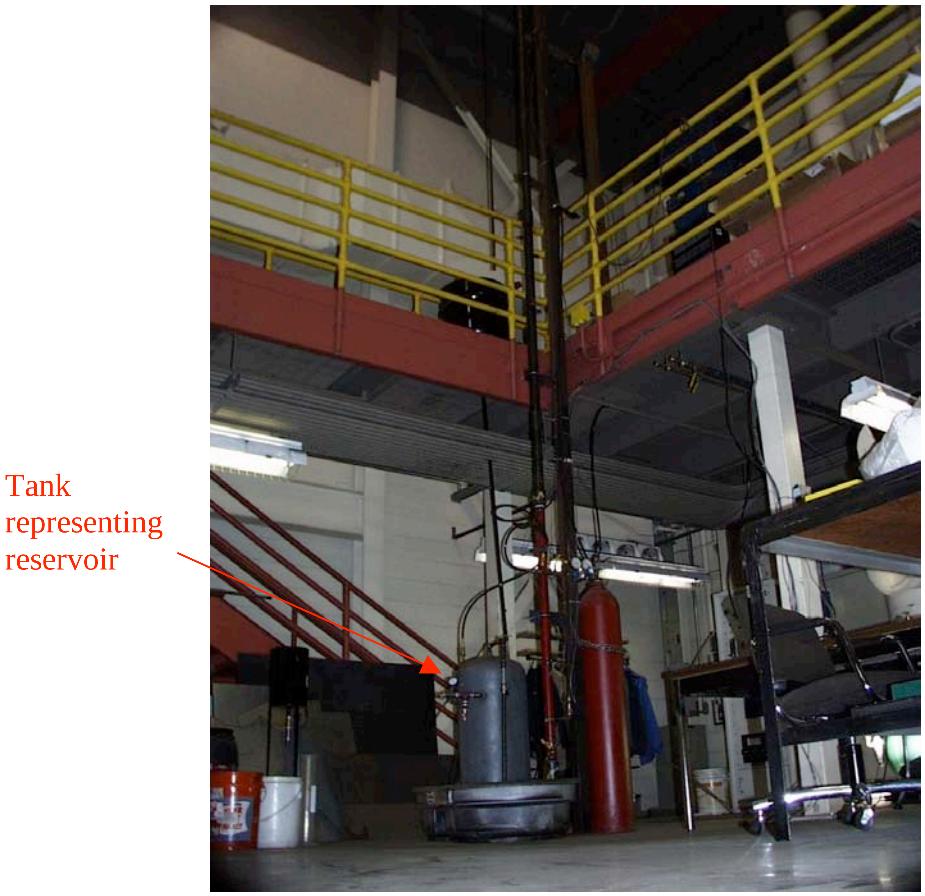

Figure 2. Chamber Lift System at Penn State

The laboratory research was done in conjunction with an initial field test in the Big Sinking Field, Kentucky. The field test was conducted by converting a producing well using a beam pump, to an intermittent gas lift system. The initial geometry was similar to the lab scale setup described above with one fundamental difference. For the first field test, the lift gas was injected down the 1 inch pipe, and fluid was to be produced up the annulus space. However, the gas compressor being used could not generate enough pressure to lift the fluid up the annulus space. So in order to successfully lift the fluid slug to the surface, the gas was injected down the annulus and the fluid produced up the 1 inch pipe. The lab scale apparatus was set up to mimic this geometry.

Objective

The objective of this study was to further develop and optimize the intermittent gas lift technology for use on low production stripper wells. Specifically, several areas were to be considered. First was a performance comparison between wells with and without a "rat hole" below the formation perforations to reduce the hydrostatic head on the formation and thereby increase fluid production. Second was to determine the optimum gas lift timing cycle to minimize the volume of lift gas consumed per barrel of fluid produced. Third was to investigate the best injection/production tubular combination. There are many different configurations that can be used along with many different tube diameter ratios that can be considered. A cross sectional area ratio between the lift string and production string was investigated in order to provide operators a "rule of thumb" for designing gas lift systems for use in other oil and gas fields. An additional goal was to measure the minimum volume of lift gas required to produce a barrel of liquid, and thereby increase the overall efficiency of the system.

2.0 Field Work

For the current SWC project, (Stage II) several changes were proposed to improve the gas lift system. The first was to replace the gas compressor with a different unit that could deliver higher pressures to the well-head. Second, two new wells were drilled specifically for this project during October 2003. These wells were drilled through the producing formation to a depth that provided approximately 300 feet of "rat hole". This permitted the positioning of the chamber of the lift system to various depths below the perferations. This permitted analyses of the system's performance using different configurations. The advantage of placing the chamber below the formation is that by adjusting the time between lifts, the fluid level in the casing can be kept at or below the perforations. If the fluid level is held below the perforations, it eliminates the hydrostatic head that the fluid column would typically put on the formation at the well bore. This allows fluid to flow into the well bore more rapidly.

The gas injection geometry was also changed to direct the gas down the annulus and produce fluid up the 1-inch string. Figure 3 shows the control valves and piping at the surface for this arrangement.

Fluid produced to stock tanks

Gas injection line

Figure 3. Well # 33

Membrane generated nitrogen was used as the lift gas for all field tests conducted because it was available on site for an ongoing huff and puff stimulation project. The gas injection line is pointed out in Figure 3. The injection of the lift gas is controlled by the large red valve that is plumbed into the gas injection line. The second red control valve shown, was not used for any of the field tests discussed in this report. Tests of the system indicated that it was not required for the operation of the system.

Figure 4 shows a schematic of well #33, one of the two new wells drilled for this project. This well was completed on October 13, 2003. The well was drilled to a total depth of 1653-feet. The wellbore diameter is 6-1/4-inches. 4-1/2-inch OD (outside diameter) casing was run to a depth of 1,627 feet. The casing was completed by perforating the casing from 1,342 and 1,362 feet. The producing formation is the Keefer sandstone located between 1,334 feet and 1,391 feet.

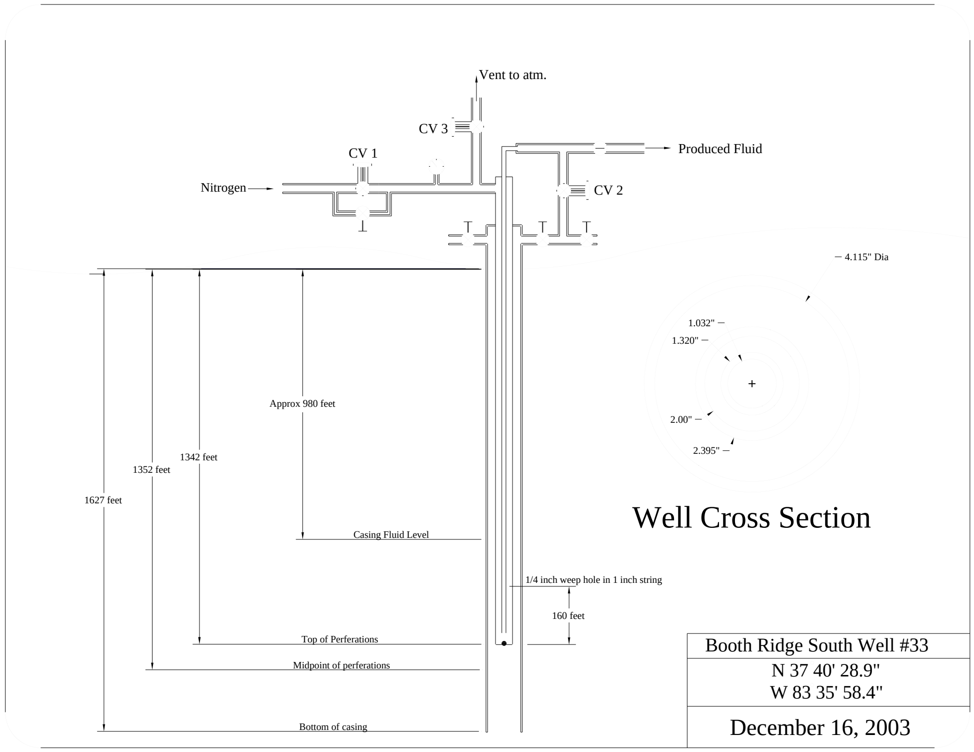

Figure 4. Schematic of Well #33

The gas injection/fluid production configuration in Figure 4 is the same as shown in Figure 3. The injection of nitrogen gas is controlled by control valve 1 (CV1 Figure 4). Nitrogen then passes down the 2-inch by 1-inch annulus to the bottom of the chamber where a standing valve is positioned at the height of the top of the perforations. The position of the standing valve was lowered deeper in the well for later testing. The slug of produced fluid is then forced up the one inch tubing string. Once the fluid reaches the surface it is directed to the separator and stock tanks via 2 inch poly tubing. The typical interval between lifts ranged from 10 to 15 minutes. A Weatherford controller powered by a small solar panel, was used to operate the nitrogen inlet control valve. The nitrogen bleed-off valve is not shown in Figure 3. Operation of this valve will be discussed more in the results section.

Special data acquisition devices were implemented to monitor and record the performance of the two new test wells. Two Omega Engineering pressure transducers from were placed in the system. One measured the pressure on the nitrogen gas supply line that is located at the surface and the second measured the pressure on the fluid production line that is also located at the surface. Data from these two transducers were recorded every 10 seconds on a laptop computer using LabView software. The volume of nitrogen used for each lift was determined using a 1-1/4 inch orifice plate. The line pressure and differential pressure were recorded on a 24 hour circular chart recorder. By integrating the circular charts, the total volume of gas used for each lift was found.

Determination of the liquid volume attained during each lift-cycle proved to be the most challenging measurement. In order to obtain this data, a trip tank was designed and fabricated. Figure 5 is a photograph of the completed trip tank plumbed into the fluid production line on one of the test wells. As viewed in Figure 5, produced fluid (oil and brine) is transported through the 2 inch plastic pipe from the lower right hand side of the photo, and up into the top of the white tank. This 55 galloon tank is semi-transparent and has graduation marks along the side that allows the operator to read off the volume of fluid from a specific lift. After a measurement has been taken, the fluid is then allowed to drain into the 30 gallon steel tank below. Nitrogen readily available from the lift gas line is then used to pressurize the bottom tank to approximately 50 psi. This pressurized nitrogen is then used to drive the fluid from the lower tank to the stock tanks. The process can then be repeated for the next lift.

Other data required for the analysis of the behavior of the chamber-lift are knowledge of the fluid height/depths in the annulus between the casing and tubing and the chamber itself. The chamber in this particular case is the inside of the 2 inch steel pipe. These measurements were made by using two different techniques. First was by using a commercially available echo meter. The echo meter works on the principle of creating a sound wave that travels from the surface, down the casing, reflects off the surface of the fluid and bounces back to the top of the well where the sound wave is picked up by a sensitive pressure transducer. Using the speed of sound of the gas in the casing, a laptop computer computes the distance down-hole to the surface of the fluid. The echo meter used for this project is shown in Figure 6, on the left side of the pipe wrench. On the far left side of the echo meter, is a small chamber that is pressurized with carbon dioxide. A firing pin device rapidly opens and sends a transient pressure wave down the casing.

Figure 5. Trip Tank to Measure Volume of Fluid Produce from a Lift

Figure 6. Echo Meter Used for Determining Fluid Level Down-hole

The second method of determining fluid levels down-hole is by using a bubble tube. A small amount of gas is injected into small-diameter tubing that is run from the surface to below the fluid level. The pressure required at the surface to move one bubble of gas from the foot of the tubing into the liquid-column is equal to the fluid head above the bottom of the bubble tube. Figure 7 shows the installation of two bubble tubes in one of the chamber lift test wells. The tube itself is ¼ inch OD, 1/8 inch ID Polyethylene tubing supplied by Cobon plastics. One bubble tube is place on the outside of the two inch steel pipe and a second is connected to a 90 degree elbow that is welded to the 2 inch pipe that permits measurement of the fluid height in the chamber. The photograph shown on Figure 7 was obtained immediately prior to lowering the 2 inch pipe into the well. Data collected using the bubble tubes will be discussed in the results section.

Figure 7. Bubble Tube Installation

3.0 Results

Two test wells (referred to as Wells# 33 and #39) were drilled specifically for this project. These wells located in the Big Andy Field in Eastern Kentucky were drilled during October 2003. Testing of these two wells began in December 2003. The original wellhead configuration permitted injection of nitrogen gas into the 2 x 1 annulus with fluid production up the 1 inch tubing string. Gas injection was controlled by an automated valve at the surface. Injection time and time between lifts were the two parameters that were varied during this set of tests.

A quarter inch weep hole was drilled in the one inch tubing string 160 feet above the standing valve. The purpose of the weep hole was to permit the pressure to equalize between the one inch string and the 2 x 1 annulus and thereby maximize the amount of liquid that would accumulate in the chamber before the next lift. The well-tender observed the presence of emulsions that coincided with initialization of production. It was hypothesized that the presence of the weep hole contributed to the formation of emulsions by increasing the amount of liquid agitation. The solution to the emulsion problem was to add a control valve at the surface that depressurized the 2 x 1 inch annulus after the fluid slug had been sent to the stock tanks. Figure 8 shows a photograph of well 33 taken January 8, 2004 shortly after the depressurization valve and vent were installed. The vent line can be seen extending above the truck in the photograph. The red control valve can also be seen mounted in the vent line.

Two pressure transducers were used to monitor the gas injection pressure and the fluid production pressure. This pressure data were monitored and recorded using a laptop computer located inside the tent shown in Figure 8. Data from one lift have been plotted in Figure 9. The nitrogen lift gas pressure and the production fluid pressure are both shown on this same plot. Gas was injected for one minute. An orifice plate and differential pressure gauge in the gas supply line were used to calculate the total volume of gas used for each lift. For this particular lift, 380 standard cubic feet of nitrogen was used to lift the fluid from the well-bore. For this lift it took approximately two and a half minutes from the time the gas injection started until the first fluid reached the surface. The production fluid pressure spiked at about 20 psi and quickly dropped to about 5 psi for the remainder of the lift. The observed production fluid pressure is largely a function of the friction and the change in the elevation of the production fluid line from the well head to the stock tanks. Well #39 was several hundred yards further away from the stock tanks than was well #33. Therefore when the fluid slug reached the surface, the observed fluid production pressure was higher.

Figure 8. Photo of Well #33 Taken Jan 8, 2004

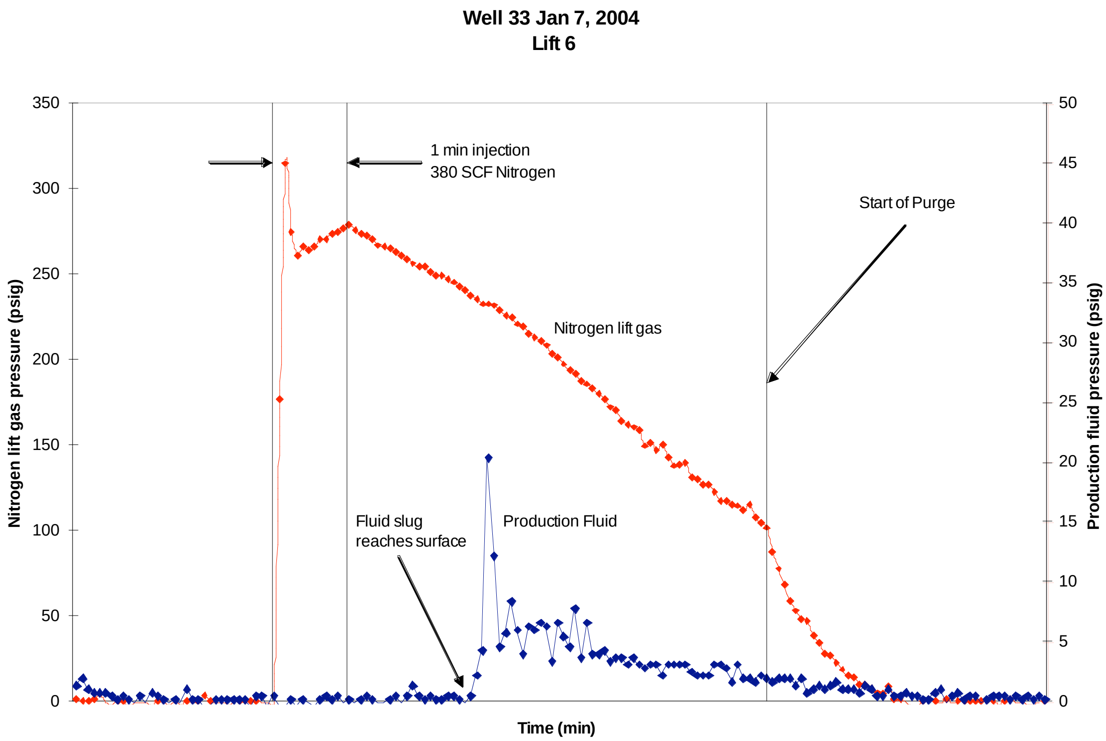

Figure 9. Pressure Data from Well #33 on Jan 7, 2004

The start of the nitrogen lift gas purge was six and a half minutes from the time the gas injection was started. The fluid slug had already reached the stock tanks by this time. Depressurizing the lift gas line was effective in permitting the chamber at the bottom to refill to its maximum capacity. However, the vented gas was a detriment as far as the overall energy efficiency of the system. The 2 by 1 inch annulus has a larger volume than the 1 inch string. Depressurizing the annulus following each cycle resulted in the venting of more gas than if the system was operated in the opposite direction. The trade off to producing in the opposite direction (fluid produced up annulus) is that there is more frictional pressure loss. The increased frictional pressure loss results from the larger surface area of the annulus space.

The next step in the field testing was to obtain an accurate measurement of the fluid produced for each lift. This measurement was obtained using the trip tank that was described in Section 2.0 of this report. During July 2004 the pipe was pulled from the well in order to permit the running of the bubble tube. The details of the bubble tube are also described in detail in Section 2.0 of this report. Figure 10 shows a picture of the service rig pulling pipe from Well #33 July 2004. When the pipe was run back into the well, ten additional joints of pipe were added in order to lower the chamber approximately 300 feet into the rat-hole. The purpose for this was to gain additional fluid volume per lift. The two inch pipe was run down-hole until it hit bottom and was then pulled off bottom about 10 feet and set into the slips.

Figure 10. Service Rig Pulling Pipe from Well #33 July 2004

Figure 11 shows the data collected from one lift on well #33 after the chamber had been lowered to a distance of about 300 feet below the perforations. Because the chamber could now accumulate more fluid than it could when it was set at the height of the perforations, each lift resulted in a larger liquid volume. Using the trip tank, the volume of this particular lift shown in Figure 11 was measured to be 18.5 gallons. The duration of the nitrogen injection was 1 minute 10 seconds and had a volume of 320 standard cubic feet of nitrogen.

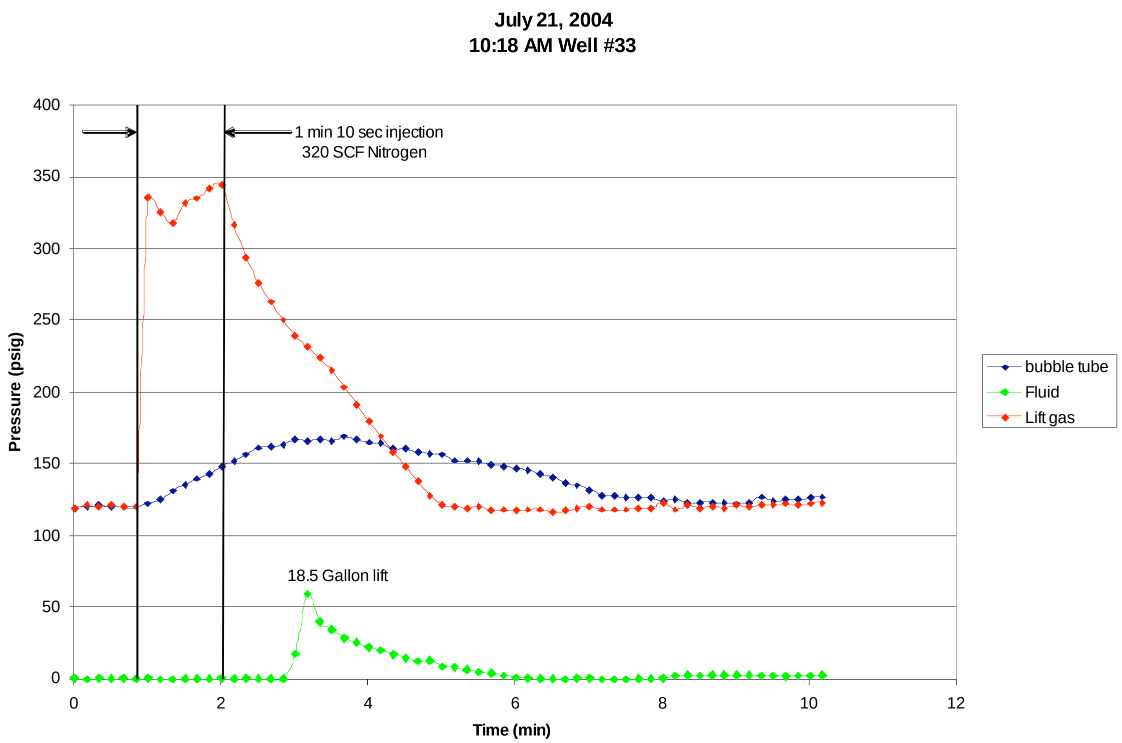

Figure 11. Pressure Data from Well #33 on July 21, 2004

4.0 Conclusions

Independent oil producer Bretagne G.P. is currently operating about 500 wells with conventional beam pumps. Nitrogen is utilized to stimulate oil-production from the Big Andy Field, Kentucky. Bretagne is evaluating the best method to expand the project by placing an additional 100 currently shut in wells, onto production. Two types of fluid lift systems are being evaluated for the additional wells: 1) down-hole electric diaphragm pump (HDESP) 2) intermittent gas chamber lift. Three of the HDESP pumps have been run and are being evaluated.

The intermittent gas chamber lift system is being redesigned with several new improvements over the systems tested to date and reported here. The current plan is to use a parallel string geometry instead of a concentric tube geometry. The parallel string geometry will offer excellent flexibility to optimize the chamber lift system design parameters such as: 1) gas supply pressure, 2) fluid volume per lift, 3) depth of lift. Also the surface control system will be re-designed to use smaller more efficient tubulars and will be easier to install with a modular control system. Current field tests with the concentric tube geometry have shown two important results. If fluid is produced up the 1 inch tubing string, there is too much tail gas produced. If the fluid is produced up the 2 by 1 inch annulus, then there is too much friction loss. This conclusion has led to the decision to pursue the parallel tubing geometry in future work.

Several other design guidelines have come out of the current field testing experience. The primary efficiency metric has been identified as the volume of lift gas used per barrel of fluid produced. A realistic target has been set for 750 cubic feet of lift gas per barrel of fluid. In order to meet this target it has been determined that a 7:1 chamber to lift string cross sectional area should be used. And also, the gas supply string should be about half the cross sectional area of the lift string.

To summarize these design guidelines, the following scenario is an example of the system being looked at for future production in the Big Andy Field. The gas lift system design parameters are: 1) gas supply pressure of 300 psi, 2) fluid volume to be lifted of 6 Barrels per day, 3) depth of lift of 1400 feet. The casing size in this example is given to be 4 ½ inch, (4.05" I.D.). Ultimately the use of 2 coiled poly tubing strings will be superior to a system of one tubular joint string to take the axial loading and a coiled second parallel string, but at this time the latter is show to be more efficient. The chamber would be located at or below the perforations and would be taking fluid off the bottom. The chamber will be designed to accumulate the size of cycle volume that will yield approximately a 300 foot column in the lift string. By limiting the size of the chamber, the difficulties with initial unloading will be minimized.

REFERENCES

1) Petrof III, E.M., “An Experimental Study of Chamberlift System Optimization”, M.S. Thesis in Petroleum and Natural Gas Engineering, The Pennsylvania State University, December 2003.

Stripper Well Consortium
Vortex Flow, LLC Technical Progress Report
Final Report

Prepared by: Jeff Boothman
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Aurora, CO 80011

Report Date: July 2004
Reporting Period: July 1, 2003 - December 31, 2004
DOE Award #: 2547-VF-DOE-1025

Report Title: **"Field Testing of the Vortex Oil and Gas Unit for Downhole Applications"**

DISCLAIMER

"Downhole Field Testing Grant"

This project was a follow-up project to work completed in 2002 where several Vortex DX downhole tool designs were tested and developed. In the course of the 2002 work, a most optimum tool design was determined to be most effective in reducing pressure loss in a tubing string and in assisting in unloading wells of liquids (mostly water). The work completed in this grant period was designed to determine the effectiveness of the technology and related tool design in a field situation and as a means of replacing ESP's and PCP's as artificial lift methods and as a means of increasing production in flowing wells,. Especially those with produced water

The scope of our project was divided into two main sections:

1) To field test Vortex DX downhole tools in live field situations to determine if the technology is effective as a replacement for PCP's or ESP's in increasing produced gas and/or produced water. In other words, can wells using these production methods be converted to 24/7 "flowing" wells.
2) To determine if the tools can be used to increase production in flowing wells.
3) To review and analyze field data to prove or disprove efficacy of the technology. Also, to take collected data to determine if any prescriptive well parameters could be set in place in order to improve the success rate of installed tools.

Seven gas wells, owned and operated by Marathon Oil Company were selected for the testing. All of the wells were in located in Wyoming in the Powder River and Oregon Basins. Wells were typically low pressure (most were below 40psi at the wellhead) and all had a variety of liquid produced, either oil and water or solely water along with produced gas. Detail of the wells is included in Table 1 in the Experimental Apparatus Section.

As a result of the work from this grant, we were able to confirm that the Vortex DX tool is effective in a field setting; however, the technology cannot be used universally as a substitute for all other artificial lift methods. See the Data Reduction section for key learnings from this project.

Experimental Apparatus: All tests were completed in operating wells in Wyoming with 7” casing and 2 3/8 tubing. Test well details at the time of installation are as follows:

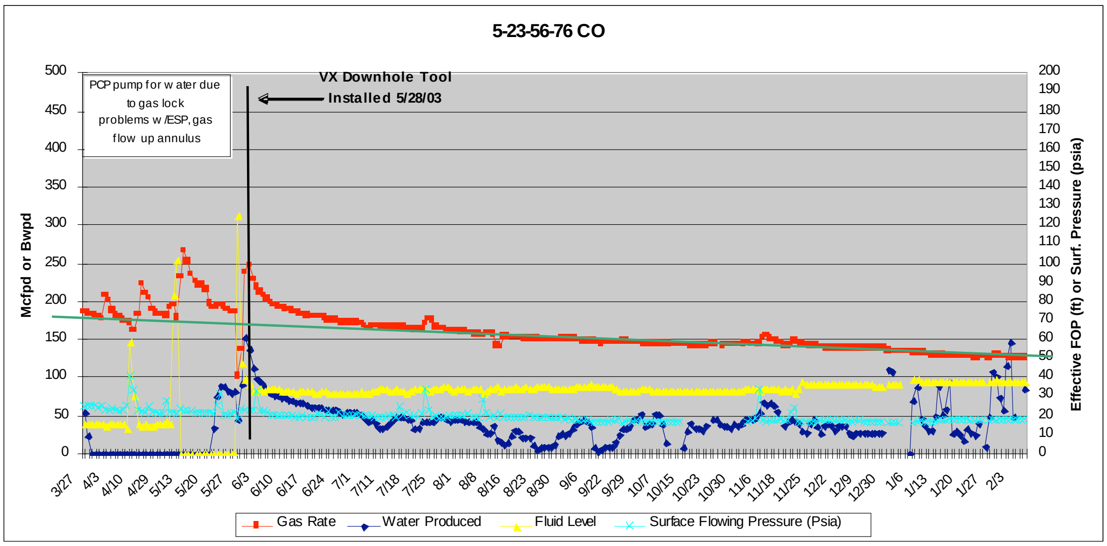
Well	Install Date	Well Depth	Casing Pressure (PSI)	Wellhead Pressure (PSI)	Gas Rate (MCFD)	Water Rate (BWD)	Basin
Oriva Hills 1-7-73 A	7/17/03	805’	30	22	60	0	Powder River
North Barker 11-3-51 A	7/11/03	860’	85	20	120	50	Powder River
West 5-23	5/29/03	623’	85	20	190	60	Powder River
Spell 12-32-A	7/24/03	562’	100	23	100	80	Powder River
Spell 8-31 -A	7/15/03	840’	115	22	0	0	Powder River
Custer 12-C	11/13/03	3,911’		75	200		Oregon
Spell 12-34	7/24/03	‘550	90	See Chart Below	See Chart Below	See Chart Below	Powder River

Tests on all wells were made with standard Vortex VX tools. Tool specifications are as follows:

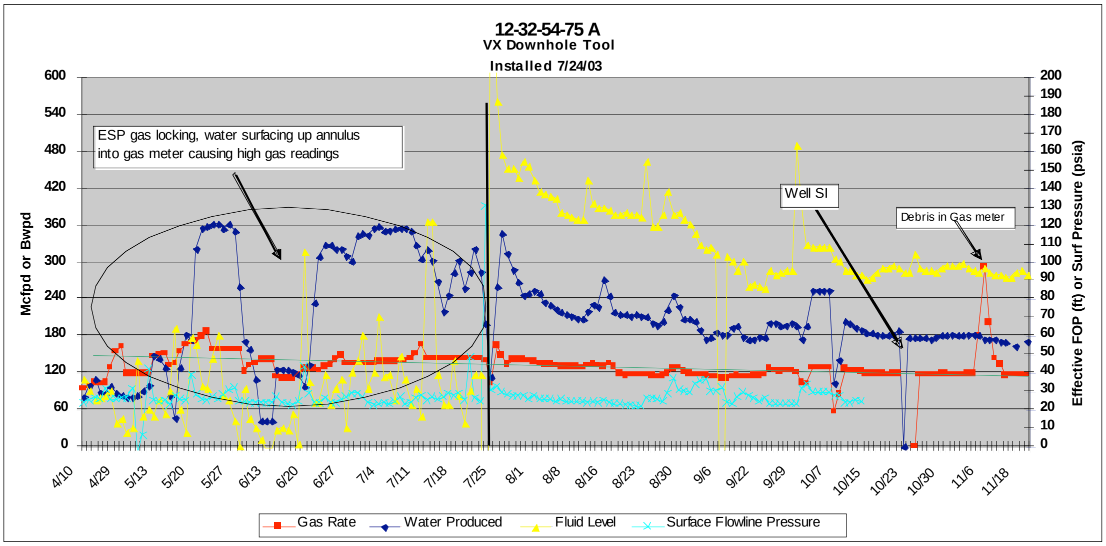
Tool size (outside diameter):	4” or 5”
Inlet Ports:	2
Inlet Chamfer:	Yes
Steel Specification:	304L Stainless
Weld Specification:	316L specification
Tubing Thread:	2 3/8”

Data Reduction:
Narrative results are given for each installation due to the extreme variability of data collected. Included is a narrative of each installation:

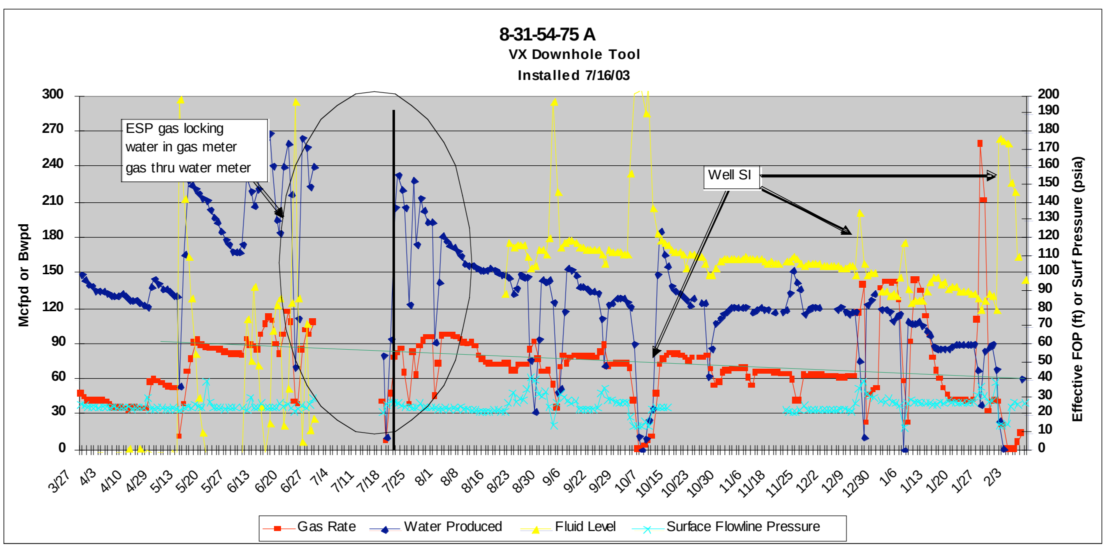
West 5-23: Prior to installation, the West 5-23 was producing 190 MCFD of gas and ~60 bd of water using a PCP pump. Production was on a rapid decline since the well was completed. The PCP pump was replaced and the Vortex VX tool was able to stabilize and maintain production at a rate similar to the pre-installation rate but on a much flatter decline curve.



Spell 12-32-A: Prior to installation, the Spell 12-32 was producing 120 MCFD of gas and ~133 b/d of water. Production for the 12 months prior to installation was erratic and ranged between 60 and 150 MCFD for gas and between 30 and 200 b/d for water using an ESP pump. The Vortex VX tool was installed on 7/24/2003 and the ESP pump removed. After installation, both gas and water rates stabilized. The water rate stabilized at ~133 b/d, the high end of the water rate range before installation. Gas rates stabilized at 120 MCFD, about 20mcfd above the previous run rate. After consistent water production for several months, the gas rate for the well then rose to ~190 MCFD**. This well was a success in that the well was converted to a flowing well, without the use of an ESP**.



Spell 8-31A: Prior to installation, the Spell 8-31 was producing water up the annulus on occasion that would reek havoc on the gas measurement as well as putting water into the gas flowline. Additionally, the water would sometimes not make it completely to surface, then fall back down the annulus and force gas into the ESP pump. This would cause the pump to gas lock and fail. After the DX tool was installed the well was able to flow consistently for a number of months. The well's non-insulated separator froze on a couple of occasions during the winter causing well downtime.



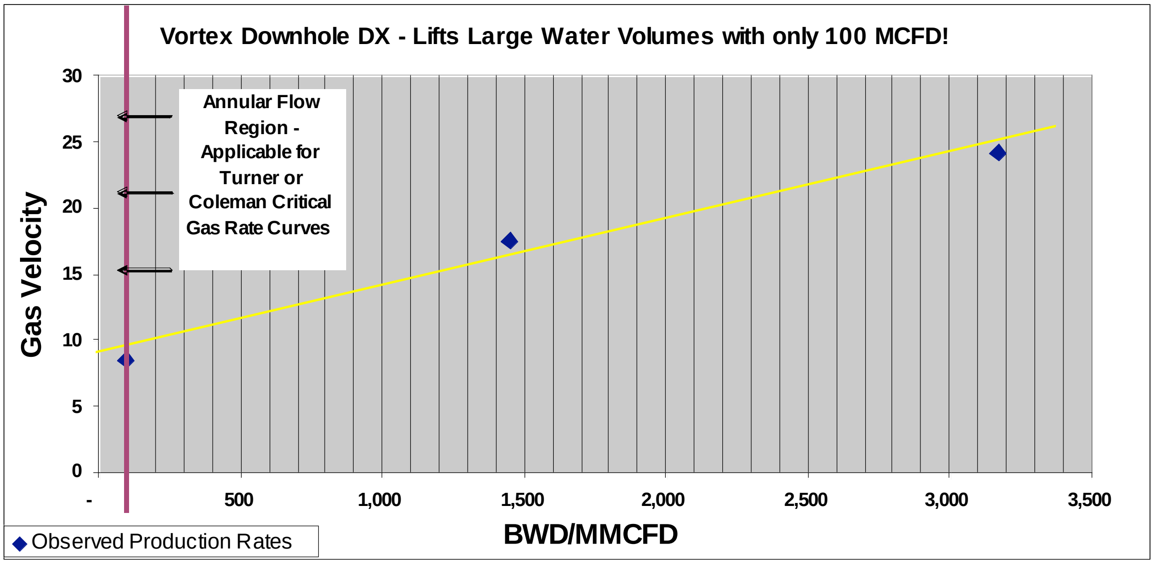
North Barker: Prior to installation the gas rate was 120 MCFD and the water rate was 20 b/d using an ESP pump. Initially, a 5" tool was installed. After installation, the gas rate fell to 80 MCFD and produced water fell to ~20 b/d. A 4" tool was installed in place of the 5" tool after about 2 month. The change did not effectively change produced gas however, produced water fell to virtually 0. Although production was greatly stabilized, it appears that the post installation gas and water rates were below pre-installation levels. It did not appear as though the 85 PSI bottom-hole pressure was adequate to lift the approx 50 BWD up the 806' of tubing. This 50 BWD appeared to be the rate that the reservoir needed to produce in order for the well to stay 'unloaded'.

Oriva Hills 1: Prior to installation, the Oriva Hills 1 was flowing ~ 60 MCFD of gas and no water using an ESP. The tool was installed on 7/17/03. After installation, the gas rate stabilized at ~60 MCFD (same as pre install levels) however, over the next several months, the gas rate increased to 70 MCFD. The lack of water in this well limited the impact that a DX tool could provide. Also, the bottom hole pressure of only 30 PSI with 22 PSI of surface pressure was insufficient to lift liquid even with a DX tool in place.

Custer 12 C: This Oregon Basin well was flowing approximately 200 MCFD of gas and small amounts of both water and oil (less than 1b/d each). After the Vortex VX installation on 11/13/03, the well was able to stay remain flowing for longer intervals without logging off. The well was not able to flow 24/7. Monthly production increases of 15-20% were seen over the course of the following six months as a result of increased on-time and some field compression being put into place in 12/03.

Spell 12-34: In this well, we carried out additional experiments where we increased the flowing wellhead pressure to see how the well would be able to lift water under various pressure conditions. We were then able to plot a straight line curve correlation between gas velocity (calculated from surface pressure and gas rate) and MMCF/BW (gas to water ratio). It should also be stated that the production rates tested went far beyond the 'annular flow region' gas/water ratios that were used by Turner and Coleman when they developed the industry standard liquid lifting curves.

	Data Point 1	**Data Point 2**	**Data Point 3**
Casing Pressure	100	94	83
Surface Pressure PSIG	60	47	27
Gas Rate MCFD	53	90	100
Water Rate BWD	5	130	266
Gas Velocity ft/sec	8.5	17.5	24.2
BWD/MCFD	94	1,444	3,167



The main conclusions drawn from data reduction are as follows:

1) The Vortex DX tools can indeed be used as a replacement for PCP and ESP systems. The key variable here is the amount of bottom-hole pressure. The bottom-hole pressure needs to be at a minimum level to support the weight of the fluid column in the tubing. In the Powder River, it appears that at least 85 PSI (for a shallow well) of casing pressure is the break point to support the typical 20 – 100 BWD.
2) The Vortex DX tools will increase produced water, oil and gas in flowing wells. Lifting 266 BWD with only 100 MCFD is an impressive result!
3) The Vortex DX is cannot be used as a UNIVERSAL replacement for both PCP and ESP systems.

Hypothesis and Conclusions:

Initial Hypothesis: The Vortex Downhole tool will organize a single or multi phase flow in a tubing string. This organized flow allows for a reduction of pressure (via a reduction in the pressure lost to a disorganized flow) in the tubing string which, in turn, allows for greater reservoir optimization (higher production rates and overall recovery) and more efficient lifting of liquids.

Conclusion: The Vortex Downhole tool is effective as a means of improving production in flowing wells. The Vortex DX can be used to convert wells currently using PCP and ESP artificial lift to flowing wells.

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March 31, 2005

STRIPPER WELL CONSORTIUM
Subcontract: 2584-LRI-DOE-1025
Lenape Resources Inc.
Prime Award No. DE-FC26-00NT41025
(PSU Log No. 68939)

Final Report: Restimulation of Under-stimulated Shallow Gas Zones Coupled With the Installation of Pumping Equipment to Dramatically Accelerate Post-Stimulation Fluid Removal

Activity Period: July 1, 2003 – December 31, 2004

Principal Authors: Karl Kimmich, John Holko

Lenape Resources Inc.
9489 Alexander Rd.
Alexander, N.Y. 14005

DISCLAIMER

ABSTRACT

Two shallow gas wells located in Chatauqua County, New York were re-perforated and re-stimulated during the third quarter of 2003. The initial well, Barney 732 was equipped with a pumping unit, and monitored for a total of three months. A pumping unit was installed on the second well, the Griswold 702, in the fourth quarter of 2003. This well was subsequently monitored for a period of 3 months with the pumping unit in place. Both wells eventually reached a point of negligible fluid production and the pumping units were removed and replaced with a tubing plunger system. Monitoring of gas production continued through the end of 2004.

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LIST OF GRAPHICAL MATERIALS

EXECUTIVE SUMMARY

It was the intent of this project to evaluate a simplistic approach to additional natural gas recovery from existing stripper wells that seem to have un-recovered reserves after approximately 20 years of production. By reviewing wellhead pressures and well logs, it was decided that there should be the potential for additional recovery. If a simple review of easily obtainable data as well as a cost effective stimulation treatment could be utilized, the potential for a dramatic impact of additional reserves from existing stripper wells was worth the effort.

The results of this project are inconclusive. Even though the initial results do not provide a dramatic increase in production, it still may be possible by prolonging the economic life through stimulation to add dramatically to the overall recovery of existing wells. The impact of using existing wells provides a positive environmental and logistical twist to the current search for additional natural gas reserves and deliverability.

EXPERIMENT

Candidate Selection

The 65 wells contained in the Lakeshore Field, Chatauqua County, New York were screened in an attempt to select the best wells for re-stimulation. The wells were ranked by the following prioritized criteria:

1. Low cumulative gas production (ie., high remaining target reserves)
2. High shut-in wellhead pressure (again; high remaining target reserves)
3. Porosity-ft. of Medina/ Whirlpool reservoir (maximum original gas-in-place)
4. Surface access (minimize logistical costs associated with equipment movement)

Two wells were selected based upon the above criteria; Barney 732 and Griswold 702. (Figure 1 and Figure 2 Well Logs Medina Section of Wells)

Fracture Stimulation Design

The fracture stimulation for each well was designed by Universal Well Services to place approximately 65,000 lbs. of 20/40 proppant carried in approximately 650 bbls of gelled water into a selected interval in each well. The design called for the sand to be placed in subsequent stages from a minimum sand concentration of 1 #/gal. up to a maximum sand concentration of 6 #/gal.

Fracture Stimulation Placement

The actual job placement record for each well is attached to this document. Each well was initially reperforated at 2 shots/ft. by Schlumberger Well Services in a 15' interval near the top of the potential pay zone. Then the bottom of each wellbore was filled with pea gravel to a point approximately 10' below the bottom of the new set of perforations. The wells were originally perforated in 1984 with a limited entry scheme – 15-16 single perforations spread out over an interval of approximately 100'.

This reperforation operation was completed in order to ensure that the entire stimulation would be placed within a small interval, thus theoretically maximizing the horizontal extent of the hydraulic fracture in the target formation.

The first stimulation was completed on the Barney 732 on September 5th, 2003 (Figure 3, Figure 4). A packer was placed on 2-7/8" tubing approximately 200' above the perforated interval. The stimulation was successfully conducted through tubing in order to protect the integrity of the twenty-year-old 4-1/2" casing.

The second stimulation was completed on the Griswold 702 on September 19th, 2003 (Figure 5, Figure 6). During the loading of the tubing prior to the placement of the stimulation, pressure was experienced on the tubing/casing annulus. A leak around the packer was suspected and the decision was made to pump down the 4-1/2" casing, without the protection of the tubing. Pressure build-up during the operation resulted in the placement of only 49,000# of proppant, approaching the design volume of 65,000#.

RESULTS AND DISCUSSION

Barney 732

The fluid recovery volume from the Barney 732 was significant and approached the total volume pumped within a few days. Subsequent inspection of the depth of sand in the well with a service rig indicates surprising results; there is no indication of proppant or pea gravel in the wellbore. The pumping unit operation was initiated and fluid recovery volumes from this point forward have been quite low – less than 100 total bbls. The gas production rate has shown no measurable change in comparison to the pre-stimulation rate, approximately 6 mcfd. Fluid level measurements indicated that the wellbore fluid level was near the pump depth. Negligible fluid production led to the removal of the pumping unit and the installation of plunger lift equipment. Monitoring of the gas production through the end of 2004 (Figure 7) indicates no noticeable improvement in production level. The excellent post-stimulation fluid recovery in this partially pressure-depleted reservoir probably indicates that the stimulation did not adequately enter the targeted porosity zone. This seems to be supported by the lack of production enhancement. In addition, the lack of proppant in the wellbore immediately after stimulation supports the theory that the re-stimulation entered the identical fracture plane of the original stimulation – which easily absorbed the deposition of the entire proppant volume. This is a problem for which we know of no simple solution. It is theorized that both the original 1984 and 2003 stimulations were placed outside of the target interval.

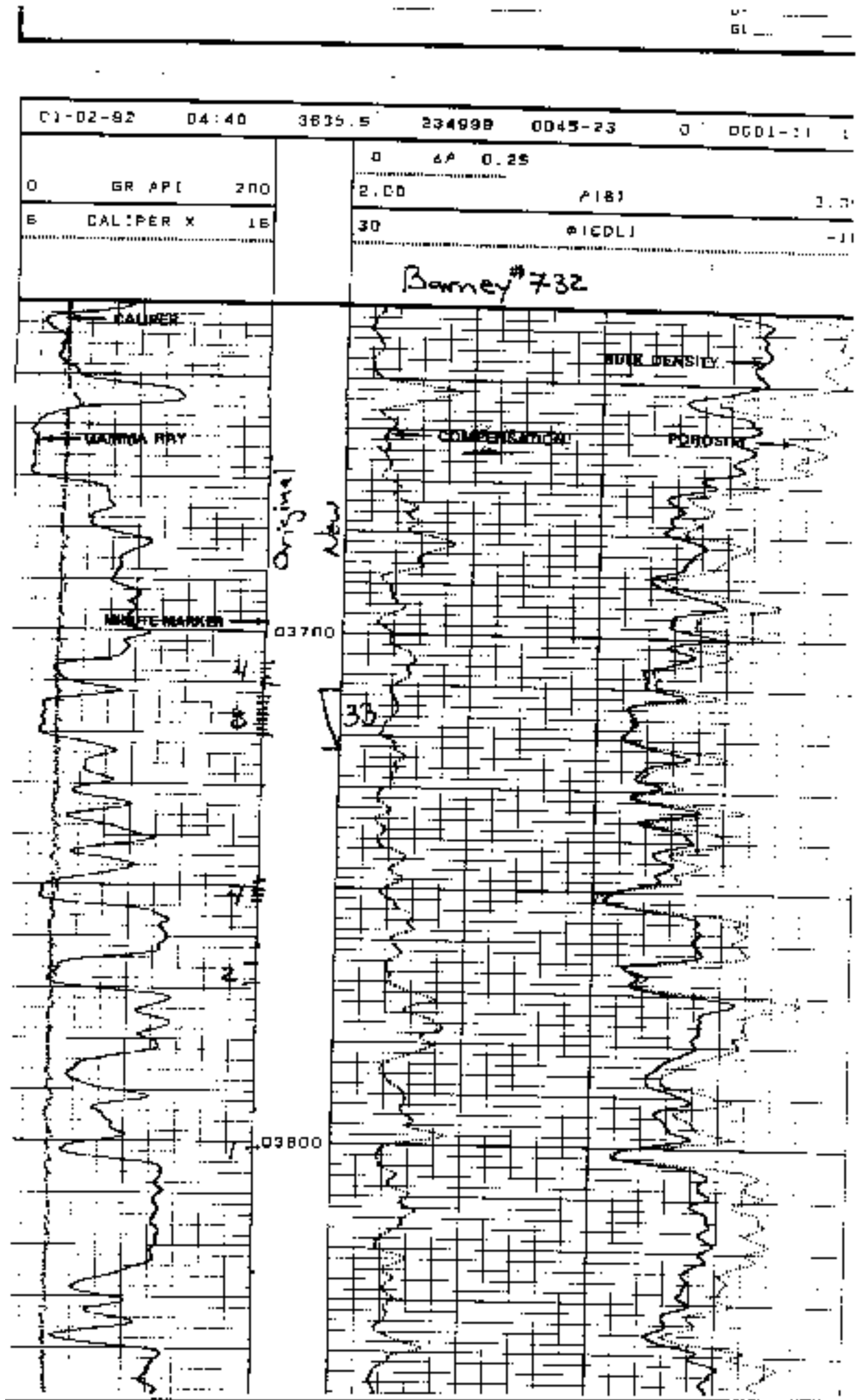
Griswold 702

Fluid recovery from the Griswold 702 totalled approximately 2/3 of the total volume pumped – 745 bbls in the 30 days after the re-stimulation. During this time period, the well built surface pressure of approximately 450 psig with a measured fluid level of approximately 1200' over the perforations. Subsequent swab operations resulted in recoveries of an additional 100 bbls of fluid when sand production led to the curtailment of swab operations. The well was sand-pumped and a pumping unit was installed. Within two months of the stimulation a production level of 535 mcf was achieved – greater than any month in the entire production history of the well. Production had declined by the end of 2004 to the 120-150 mcf/month range (Figure 8). Although this rate is disappointing, it remains higher than that historically exhibited by the well. It appears that the re-stimulation was successful in entering a portion of the reservoir that was previously unstimulated. The sudden pressure increase experienced during the re-stimulation that resulted in a premature completion of the job seems to indicate that the proppant was entering a previously unstimulated zone.

CONCLUSION

Trying to design a simple re-completion program to recover additional reserves from existing stripper wells may be economically successful during times of high natural gas prices, but may not be as simple as just adding additional proppant to existing zones. The key to additional recovery will be an ability to define and isolate understimulated zones. Additional technology and research will need to be applied to this review to provide an adequate understanding of the relationship between stimulation and recovery in the Medina Fields of Western, New York. There are no immediate plans to conduct additional re-stimulations in this field. Although there remain a large number of understimulated wells, there appears to be no low-risk method at this time, which would allow isolation and re-stimulation of the unstimulated zones(s). Several new wells will be drilled and completed during 2005 and 2006. During the drilling and completion of these new wells, additional reservoir data will be collected in an attempt to ascertain whether zonal confinement of fracture stimulations in this field is feasible.

Figure 1


01-02-92
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234998
0045-23
GR API
200
CALIPER X
16
2.00
30
0.25
Barney #732
CALIPER
GAMMA RAY
BULK DENSITY
COMPENSATION
POROSITY
original
new
03700
33
03800

Figure 2

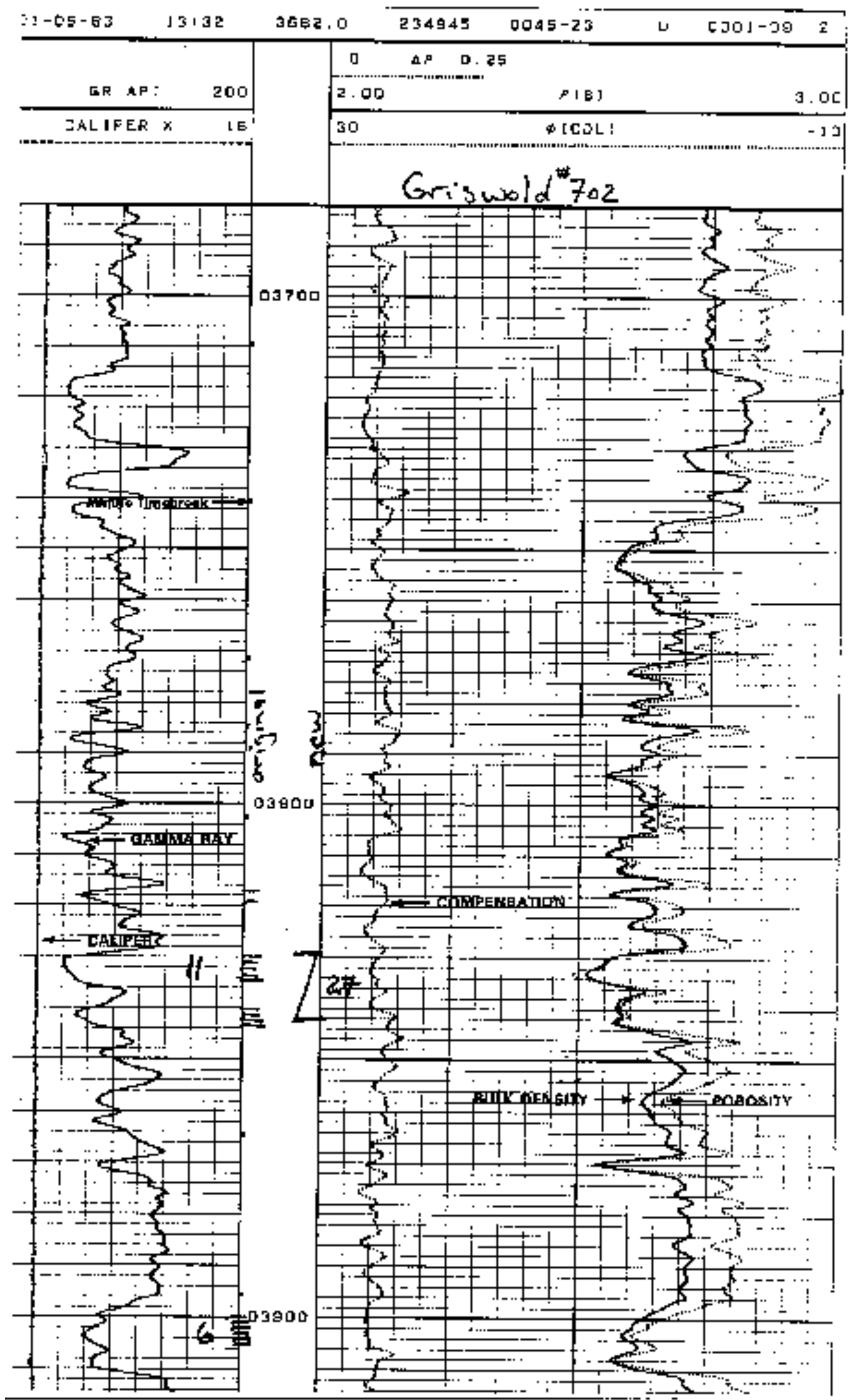

Griswold #702
GR API 200
CALIPER X 16
2.00
3.00
30
03700
03800
03900
GAMMA RAY
CALIPER
COMPENSATION
BULK DENSITY
POROSITY
original
new
27
11
6

Figure 3

Lion Energy

Date:	**9/5/03**
Well:	**Frank R. Barney #1 - 732**
Location:	**Chautauqua County, NY**
Perforations:	**3,706'-3,722' 33 Holes**
Packer Depth:	**3212'**
Job Description:	**Water frac through 2 7/8" tubing. 40# Linear Gel**

Job Summary

Average Slurry Rate	19.8	bpm
Maximum Slurry Rate	23.4	bpm
Slurry Volume	29,482	gals
Sand Total	648	sacks
Average Sand Concentration	2.8	Lbm/Gal
Maximum Sand Concentration	5.4	Lbm/Gal
Average Pressure	3374	psi
Maximum Pressure	4198	psi

Figure 4

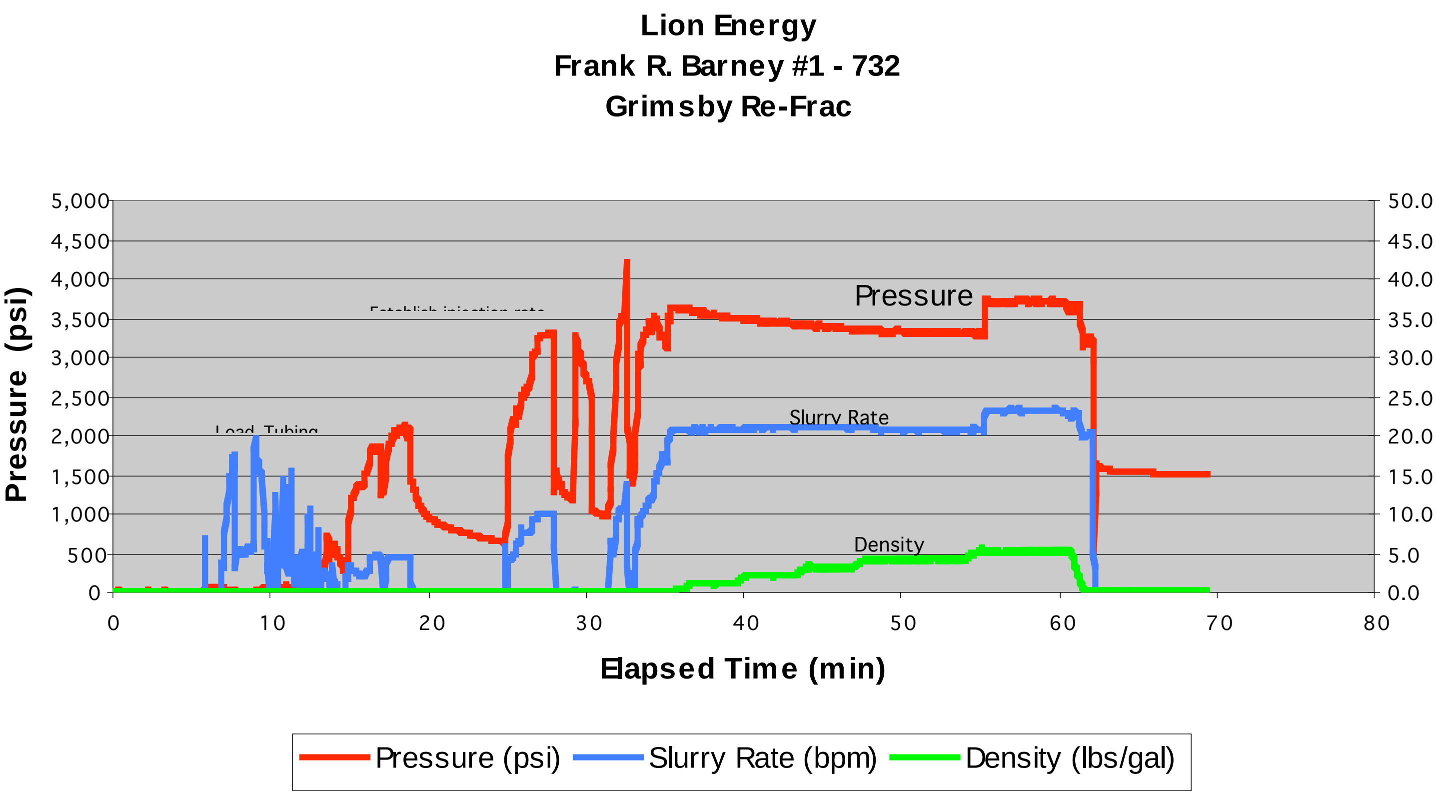

Lion Energy
Frank R. Barney #1 - 732
Grimsby Re-Frac
Pressure (psi)
Elapsed Time (min)
Pressure
Slurry Rate
Density
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
0.0
5.0
10.0
15.0
20.0
25.0
30.0
35.0
40.0
45.0
50.0
0
10
20
30
40
50
60
70
80
Pressure (psi)
Slurry Rate (bpm)
Density (lbs/gal)

Figure 5

Lion Energy

Date:	**9/19/03**
Well:	**R.Griswold #1 - 702**
Location:	**Chautauqua County, NY**
Perforations:	**3,829' - 3,842' 27 Holes**
Job Description:	**Water frac through 41/2" Casing, 30#-40# Linear Gel**

Job Summary

Average Slurry Rate	18.4bpm	
Maximum Slurry Rate	21.2bpm	
Slurry Volume	31,247gals	
Sand Total	490sacks	(Appx. 420 Sacks in Formation)
Average Sand Concentration	2.0Lbm/Gal	
Maximum Sand Concentration	4.2Lbm/Gal	
Average Pressure	3483psi	
Maximum Pressure	4170psi	

Figure 6

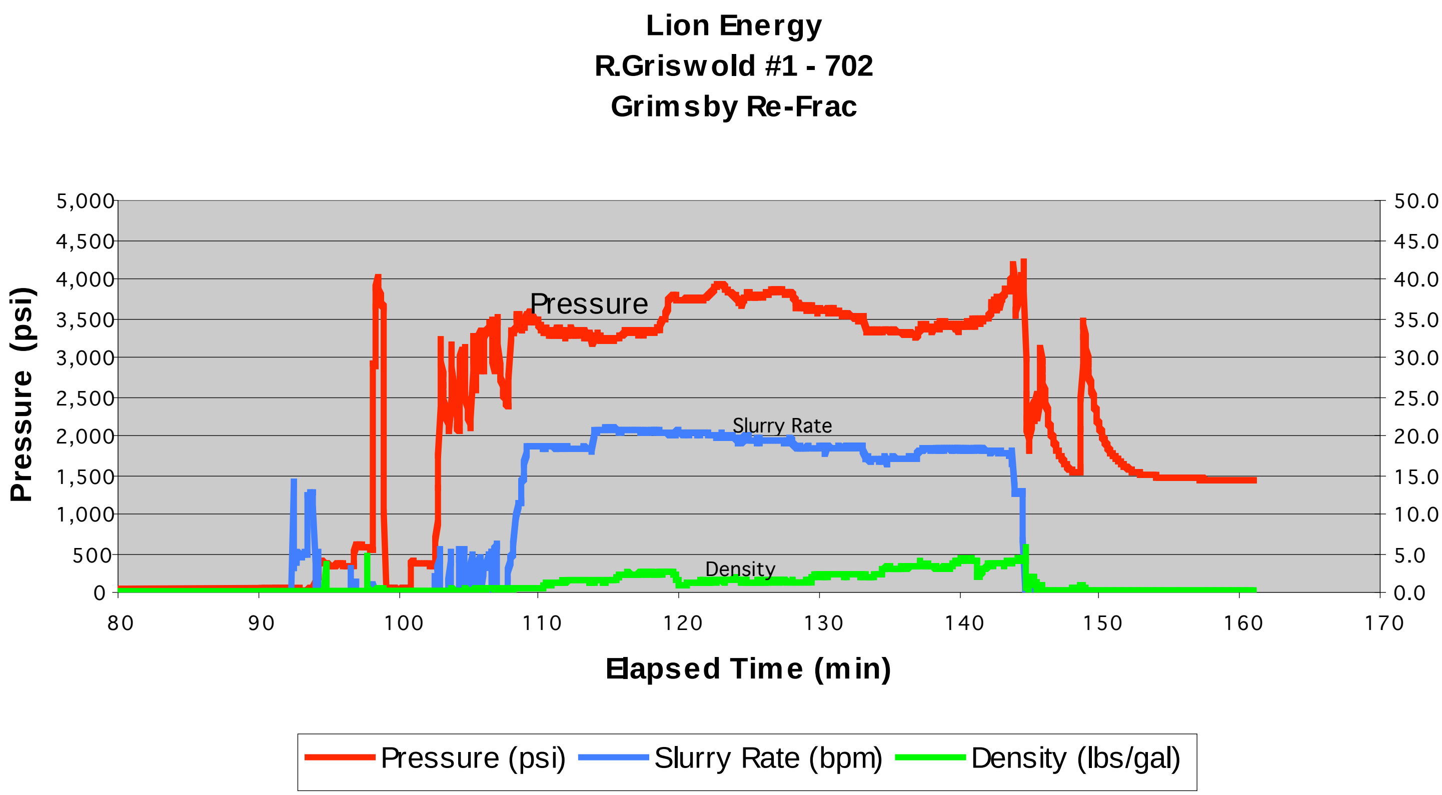

Lion Energy
R.Griswold #1 - 702
Grimsby Re-Frac
Pressure (psi)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
80
90
100
110
120
130
140
150
160
170
Elapsed Time (min)
Pressure
Slurry Rate
Density
Pressure (psi)
Slurry Rate (bpm)
Density (lbs/gal)

Figure 7

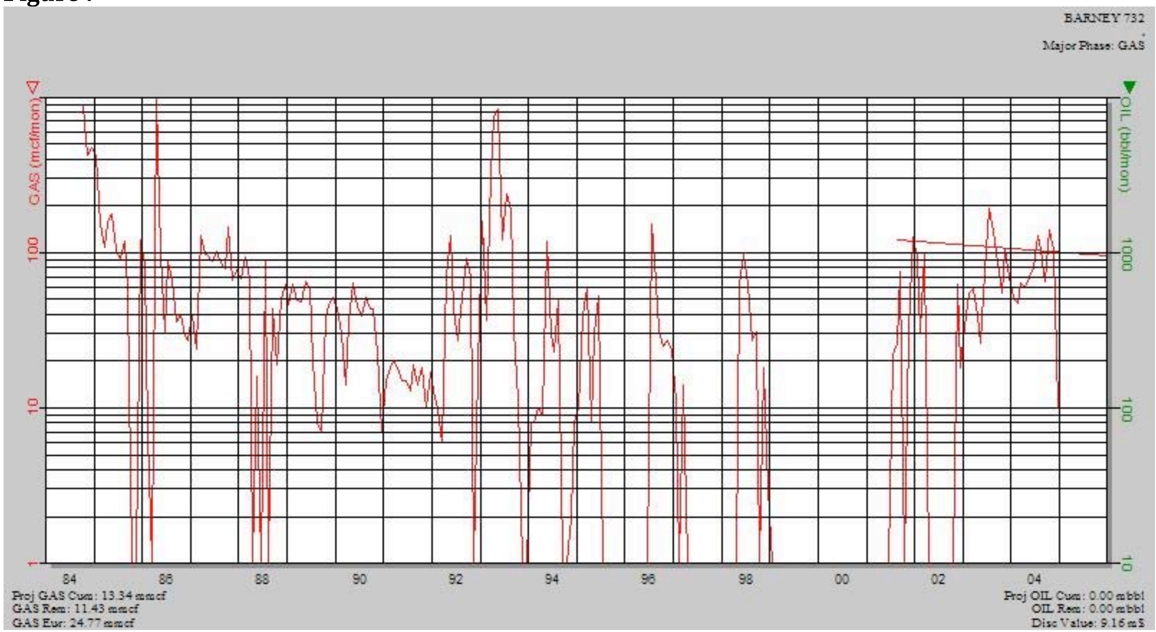
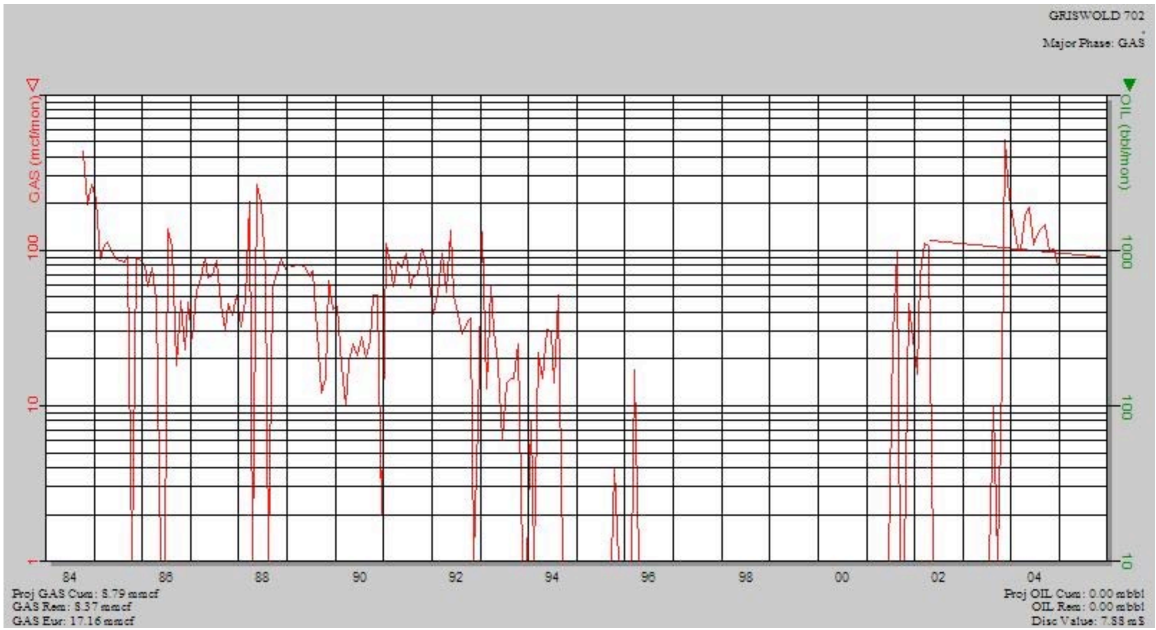

BARNEY 732
Major Phase: GAS
GAS (mcf/mon)
OIL (bbl/mon)
Proj GAS Cum: 13.34 mmcf
GAS Rem: 11.43 mmcf
GAS Eur: 24.77 mmcf
Proj OIL Cum: 0.00 mbbl
OIL Rem: 0.00 mbbl
Disc Value: 9.16 m$

Figure 8


GRISWOLD 702
Major Phase: GAS
GAS (mcf/mon)
OIL (bbl/mon)
100
10
1
1000
100
10
84
86
88
90
92
94
96
98
00
02
04
Proj GAS Cum: 8.79 mmcf
GAS Rem: 8.37 mmcf
GAS Eur: 17.16 mmcf
Proj OIL Cum: 0.00 mbbl
OIL Rem: 0.00 mbbl
Disc Value: 7.88 m$

Enhanced Real-time Propellant Activation during Downhole-mixed Fracture Stimulation Process for Low-permeability Stripper Wells

Final Report

Reporting Period: July 1, 2003-December 31, 2004

PI: George L. Scott III
Realtimezone, Inc.
100 North Pennsylvania,
Roswell, NM 88203

Date: May, 2005
2549-RTZI-DOE-1025

Enhanced Real-time Propellant Activation during Downhole-mixed Fracture Stimulation Process for Low-permeability Stripper Wells

ABSTRACT

Enhanced fracture stimulation processes are generally used in the petroleum industry to increase the recovery of hydrocarbon reserves. In the in the United States in particular, more efficient and cost-effective reservoir fracturing treatments are needed to enhance the recovery of oil and natural gas in those stripper wells that are characterized by low-permeability reservoirs. Proposed is a well test project comprising the development and field-testing of a novel fracture stimulation that utilizes a chemically-induced in situ fracturing process that is combined with hydraulic fracturing stimulation to maximize reservoir fracture propagation.

Proposed is the research and development of a down-hole blending mixture of propellants and various oxidizers that are pumped separately (and safely) down the wellbore for reaction and generation of secondary fracturing energy in the hydraulically induced reservoir fracture. With the proposed process, various propellants may be pumped down the casing for admixture with oxidizers to generate secondary fractures to augment the fractures created by hydraulic fracturing, which theoretically should result in greater fracture length extension and significantly enhanced hydrocarbon flow to the wellbore. Proposed are the admixture of propellants and oxidizers, including encapsulated or time-delay propellants and activators, concurrent with NETL-RealtimeZone's patented downhole-mixed stimulation process, whereby one stimulation component is pumped down the casing while the second stimulation fluid (energizing gases and/or proppants may be included in either fluid) is pumped down the tubing and thereby blended down-hole to form, in real-time, a composite fracturing fluid prior to entry into the reservoir fracture. Encapsulated or otherwise time-delayed chemical reactions may be used to facilitate placement of the propellants further into the reservoir formation, prior to reaction. This simple well completion system is safely and easily utilized at the well site and enables dramatic improvements in reserve recovery efficiency, safety, and cost savings.

This proposed project would be field tested initially in a stripper well with a low permeability reservoir in the Permian Basin, however, success of this proposed novel fracturing technique would prove up numerous applications in other lower permeability oil and natural gas stripper reservoirs in geographic basins throughout the United States, and ultimately worldwide. The cost savings and value of enhanced reserve recoveries that could be provided by widespread industry application of this technology are potentially substantial. Deliverable work product would include a patent application related to this project, which if commercialized would be widely licensed to all interested stimulation service providers.

TABLE OF CONTENTS

LIST OF GRAPHICAL MATERIALS

INTRODUCTION

Realtimezone, Inc. has recently conducted research and development of patented systems for downhole-mixed stimulation processes and a real-time tracer diagnostic and fracturing procedure that are partially funded by the Department of Energy's National Energy Technology Labratory and by contributions of effort and services from several energy service providers in the Permian Basin of New Mexico. As discussed via paper presentation at the Society of Petroleum Engineering (SPE)'s Annual Technical Conference and Exhibition in October, 2002, (SPE 77676; *Real-Time Downhole-Mixed Stimulation Fracturing Process*, by Scott, Covatch & Carrasco) multiple stimulation field-tests to date have successfully proved the concept of downhole-mixing of composite fracturing fluids. This field proven real-time stimulation system results in lower treating pressures and the ability to modify stimulation treatments on the fly, however, further research and experimental stripper well test work is hereby proposed for the development of a propellant-enhanced test procedure that is comprised by in situ ignition of propellant concurrent with a hydraulic fracturing process. The proposed stripper test well is located in Eddy County, New Mexico.

It is anticipated that if successful, this experimental well test work will safely demonstrate the logistic simplicity of the proposed propellant-downhole-mix fracturing process, which should result in increased reservoir fracture extension and greater reserve recoveries in stripper wells chararacterized by low-permeability reservoirs. Safety considerations are paramount with any explosive propellant system, and this proposed experimental process provides prudently cautious methods for safely achieving improved reservoir hydraulic-chemical fracture propagation.

EXECUTIVE SUMMARY-

The research, development and field-testing of an experimental reservoir stimulation process for stripper wells was proposed in a stripper well located in the Permian Basin. Proprietary experimental processes were evaluated for the proposed well test pumping of a patent-pending, chemically-induced in situ fracturing process concurrent with RealtimeZone's patented, downhole-mixed hydraulic fracture stimulation process.

The proposed down-hole blending of a chemical mixture of propellant and oxidizer was designed to be pumped separately, and safely, to generate secondary fracturing energy within the hydraulically induced reservoir fractures. The propellants would be pumped down the casing for admixture with oxidizers that are pumped down tubing to generate an energy release in the hydraulically-induced formation fractures, which theoretically should create secondary fracture extensions. A primary goal is safely achieving greater overall fracture extension in situ by downhole-mixed chemical reaction, which will enhance hydrocarbon flow to the wellbore further than is typically accomplished by hydraulic fracturing processes alone.

The proposed admixture of propellants and oxidizers, including encapsulated or time-delay propellants and activators, would occur concurrent with hydraulic fracturing, whereby one stimulation component is pumped down the casing while the second stimulation fluid (gases, energized fluids and/or proppants may be included in either fluid) is pumped down the tubing and thereby blended down-hole. It is anticipated that this chemical-hydraulic fracturing process will be safely and easily pumped at the experimental well site, and as such would enable dramatic improvements in reserve recovery efficiency, safety, cost savings, and overall reservoir fracturing success due to greater fracture propagation compared to existing hydraulic fracture processes.

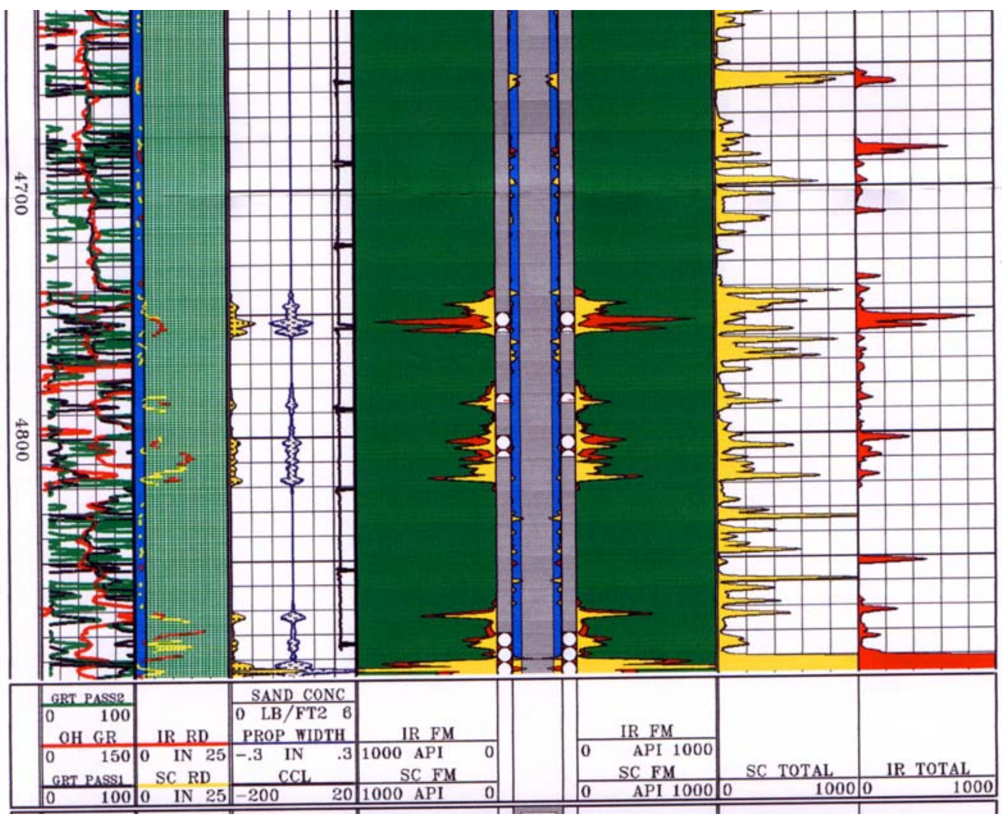
A provisional patent application was filed and further research conducted pertaining to propellants, oxidizers, and the use of said materials in the downhole environment. An extensive patent search found only one relevant U.S. patent that was slightly related to the proposed propellant-activation process. Thus it was anticipated that after the field-test, deliverable work product would include a continuation of the existing patent-pending application. However, field-testing was not accomplished due to the unexpected reluctance to participate by the major oilfield stimulation service companies. This sudden reluctance was unanticipated and was reportedly (from verbal communications with various service company personnel) due to a U.S. well site accident that occurred either in late 2003 or 2004 that resulted in the serious injury and death of well site personnel due to the accidental surface-discharge of propellants.

At this juncture, we remain disappointed that there are no stimulation service providers interested in conducting a well test, at virtually any cost, due to their paranoia

regarding safety issues. The proposed chemical-hydraulic fracturing process would be safer than any other known process for ignition of propellant to generate reservoir fractures, however, Realtimezone remains unsuccessful in convincing service companies to participate in an experimental well test as earlier proposed. Ongoing research and the patent-pending application has been shelved, and if any stimulation companies have future interest in propellant-activated stimulation, it is freely available.

EXPERIMENTAL

In an experimental field test conducted in March, 2003, oil production was increased in a stripper well from 8 BOPD to a steady rate of 20 BOPD by downhole-mixing of Nitrogen, Borate gel and proppant, which was effectively placed into the reservoir as evidenced by the post-stimulation tracer survey shown below (Exhibit One).



This same process of downhole-mixed stimulation was planned for the proposed propellant-fracturing well test project. Ongoing research and development was conducted from May 2003 through May 2004 to evaluate and delineate the best methods of implementation of the proposed system. After an extensive search of literature and issued patents, a pertinent United States patent by Colgate, et al (SEE APPENDIX i) was used to help the project investigator better develop an improved propellant-induced fracturing process that relied on downhole-mixing to provide numerous safety features. Colgate's patent provided for use of solid or semisolid propellant grains that were packed together in the wellbore so as to create voids within the propellant volume, with said grains of near-uniform size such as could be easily pumped along with proppant-sized material. With said grains bonding together under sufficient strength due to hydraulic pressure, Colgate theorized that this packing of propellant would substantially delay the fluidization of the propellant that might naturally occur by the onset of Taylor unstable burning.

Avoidance of Taylor unstable burning is desirable to prevent the undesirable launching (i.e. like a rocket) of the drill pipe during the stimulation process. Colgate's patent claims included having spherical propellant grains are bonded together with a glue that would also function as a propellant or propellant component. The propellant types included ammonia-based chemicals, nitrocellulose, black powder, various fuels, polymerized Rubber and Aluminum, and a monobase or double base propellant comprised from the group consisting of nitrocellulose in combination with nitroglycerine. Said glue types include epoxies, polycarbonates and ureas, however, besides glue.

Colgate's patent also claimed the use of a viscous fluid, such as viscous petroleum oil, for suspension of the propellant grains for the purpose of avoiding fluidization and too-rapid burning of the propellant, which would theoretically result in the onset of Taylor unstable burning and potentially the dangerous and undesirable launching of the well's tubing or casing string. The uncontrolled growth of a Taylor instability due to rapidly burning propellant surface leads to an uncontrolled increase of burning area and hence the uncontrolled increase of pressure. Taylor instability may initiate detonation and the explosive energy release of detonation. Hence, uncontrolled Taylor instability growth is to be avoided for these purposes. According to Colgate, Taylor instability may be prevented by use of solid propellants that have pores filled with viscous and slow-burning materials.

The reasoning for having the wellbore-packed propellant burn relatively slow is to generate fracturing gas pressure in a time that is a small multiple (e.g. 2 to 10 times) of the dynamic time of the system. In this regard, it is not desired to shock the formation because this compacts the rock and wastes energy that would otherwise be used to deform and initiate and propagate fractures. Fracturing with detonating explosives typically results in a shock wave that generally compacts the reservoir rock, as opposed to opening new fractures. While a slower gas release is thus desired, too slow a release results in the gas or fluid bleeding off into the formation.

By downhole-mixing of propellant and oxidizers, as planned in the proposed well test, the undesirable incidence of Taylor unstable burning is avoided by control of the propellant burn rate, which controls resultant pressure generation. Realtimezone's work to date includes a U.S. Patent; *Real-time reservoir fracturing process* (Scott & Covatch) that is incorporated by reference (SEE APPENDIX ii). A similar dowhole-mixed process would substantially improve the processes and safety of downhole propellant activation. Furthermore, this work has resulted in the proposed process of downhole-mixing of propellant with a foaming agent such as Nitrogen or Carbon Dioxide, which lessens propellant grain-to-grain contact geometries and at small concentrations could be used in real-time to control propellant burn rate (and thus totally avoid Taylor unstable burning). The particular advantage of downhole-mixing is that the oxidizer and propellant are physically separated until admixture in the reservoir fractures. This approach is much safer to handle and transport and is practically immune to unexpected surface detonation.

Colgate's patent mentions in a less preferred embodiment that pumping of the propellant slurry could be accomplished via a down hole nozzle during burning and at a velocity sufficiently great so that the burn front does not climb up the injection string (thereby either launching the tubing string or reaching the surface as an explosion). However, certain difficulties occur with this approach. First, the viscosity of the oil must be low for rapid pumping, yet high in order to minimize the burning rate of the propellant. In other words, a lower viscosity will give too high a burn rate and higher viscosity oils are essentially hard to rapidly pump, due to viscous pipe losses. Also, if a slurry of pre-mixed fuel and oxidizer is pumped at a high pressure, there is the potential danger of ignition by friction in the pump valves or pipe, which could lead to an explosion. Avoidance of these potential dangers further supports mixing the propellant down hole for safe, in situ combustion within hydraulically-induced fractures.

RESULTS AND DISCUSSION

Proprietary experimental processes were evaluated for the proposed well test to facilitate the pumping of a patent-pending, chemically-induced in situ fracturing process concurrent with RealtimeZone's patented, downhole-mixed hydraulic fracture stimulation process. The proposed down-hole blending of a chemical mixture of propellant and oxidizer was designed to be pumped separately, and safely, to generate secondary fracturing energy within the hydraulically induced reservoir fractures. The propellants would be pumped down the casing for admixture with oxidizers that are pumped down tubing to generate an energy release in the hydraulically-induced formation fractures, which theoretically would create secondary fracturing and pressure generation to extend the hydraulically-induced fractures.

A comprehensive review of patents issued through 2004 was conducted along with interviews of numerous oilfield personnel that indicated experience with propellant stimulation treatments, mostly related to the downhole-ignition of jet fuel, however, this study included a review of explosive canisters used in wells since 1985 in New Mexico by various companies. After detailed analysis it was decided to proceed with a well test using jet fuel that would be pumped behind a methanol foam frac job into the hydraulically-induced fractures and then ignited by downhole mixing with oxidizers.

The proposed admixture of propellant and oxidizer in the well test would occur concurrent with hydraulic fracturing, whereby one stimulation component is pumped down the casing while the second stimulation fluid is pumped down the tubing and thereby blended down-hole. It was anticipated that this chemical-hydraulic fracturing process would safely and easily be pumped at the experimental well site, and as such would enable dramatic improvements in reserve recovery efficiency, safety, cost savings, and overall reservoir fracturing success.

A chemist was retained by Realtimezone to assist in the project work and a provisional patent application was filed concurrent with further chemical research of propellants, oxidizers, and the use of said materials in the downhole environment. It was generally anticipated that after the field-test, deliverable work product would include a continuation of the existing patent-pending application. However, field testing was not accomplished due to the unexpected reluctance to participate by the major oilfield stimulation service companies. From earlier positive indications, this sudden reluctance was unanticipated and was reportedly (from verbal communications with various service company personnel) due to a U.S. well site accident that occurred either in late 2003 or 2004 that resulted in the serious injury and death of well site personnel due to the accidental surface-discharge of propellants.

At this juncture, we remain disappointed that there are no stimulation service providers interested in conducting a well test, at virtually any cost, due to their paranoia regarding safety issues. The proposed chemical-hydraulic fracturing process would be safer than any other known process for ignition of propellant to generate reservoir fractures, however, Realtimezone remains unsuccessful in convincing service companies to participate in an experimental well test as earlier proposed. Ongoing research and the patent-pending application has been shelved as a result. If any stimulation companies express future interest in propellant-activated stimulation, this technology will be made freely available and as such, the work done to date was instrumental in determining that a safer and more efficienct process exists for downhole-ignition of propellants for the purpose of enhanced reservoir stimulation.

REFERENCES

*****_Real-Time Downhole-Mixed Stimulation Fracturing Process_, SPE 77676, by George Scott III, Realtimezone, Gary Covatch, NETL, and Art Carrasco, Halliburton
Copyright 2002; Society of Petroleum Engineers Inc.

*This paper was prepared for presentation at the SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, 29 September–2 October 2002.

Fast-burning nitrocellulose compositions, U.S. Patent No.6,645,325, November 11, 2003 by Russell Nickel

Modified nitrocellulose based propellant composition, U.S. Patent No. 5,218,166, June 8, 1993, by Schumacher; John B

BIBLIOGRAPHY

George L. Scott III

EDUCATION

1981: B.S. Geology with academic emphasis in Petroleum Engineering-New Mexico Tech @ Socorro, New Mexico.
1983: Graduate study in geophysics & petroleum engineering-U.T. @ Austin, Texas. Also numerous courses related to petroleum recovery, E.O.R., reservoir evaluation and well stimulation procedures. Law school courses related to patenting processes and intellectual property law.

EMPLOYMENT

1981-1982: Drilling rig roughneck
1983-1988: Well log analyst- Permian Basin of Texas and New Mexico. Work included well site evaluation, petroleum reservoir mapping
1988-1990: Exploitation manager for Permian Hunter Corp.
1990-1992: Manager of exploration and reservoir stimulations for Strata Production Company in the Permian Basin, New Mexico & Texas.
1992-1996: Well consultant in the Permian Basin, New Mexico and Texas.
1997-1998: CO_2 field development geology for Ridgeway Arizona in Arizona
1998-1999: Research & development of oilfield technologies, RealtimeZone
1999-Present: Development of patented stimulation procedures and real-time diagnostic system working with Department of Energy (NETL) and licensed to Halliburton Energy Services.

PROFESSIONAL ACCOMPLISHMENTS

Pioneered research and development of innovative solutions related to real-time reservoir completion processes. Expertise gained through hundreds of well completions in Colorado, Texas, Arizona and New Mexico. Reservoir delineation of significant reserves in numerous oil and gas fields in the Permian Basin. Geologic discovery of proven reserves of 3.0+ TCF in U.S.'s third largest CO2 & Helium gas field in Arizona. Solved various well completion problems common to industry and authored or co-authored numerous U.S. Patents related to oilfield technology, including (a) commercially utilized pipelift machine to eliminate chronic oilfield injuries, (b) real-time downhole-mixed fracturing system, and (c) real-time tracer diagnostic system. Associated with RealtimeZone, a company specializing in reservoir evaluation, real-time reservoir fracturing and reservoir spectral analysis. Membership in S.P.E., AAPG, and Roswell Geological Society.

LIST OF ACRONYMS AND ABBREVIATIONS

RTZ: RealtimeZone, Inc.
P.I.: Principal Investigator (George Scott)
NETL: National Energy Technology Laboratory
HES: Halliburton Energy Services
CO2: Carbon Dioxide
N2: Nitrogen

APPENDICES

i

United States Patent

4,681,643

Colgate , et al.

July 21, 1987

Fast burning propellants

Abstract

A solid or semisolid propellant comprising grains of propellant or propellant components bonded together so as to create voids within the propellant volume, said grains bonded together with sufficient strength to substantially delay the fluidization of the propellant by the onset of Taylor unstable burning, said propellant having a rapid burn rate below that associated with Taylor unstable burn. In another embodiment, the grains are held within and the voids are filled with viscous fluid binder such as a petroleum oil, said binder functioning to hinder Taylor unstable burning and yet permit very rapid burning within the propellant volume.

Inventors:
Colgate; Stirling A. (4616 Ridgeway, Los Alamos, NM 87544); Roos; George E. (P.O. 284, Burns Flat, OK 73624)
Appl. No.:
538578
Filed:
October 3, 1983

Current U.S. Class:
149/21; 149/2; 149/43; 149/44; 149/46; 149/61; 149/63; 149/65; 149/72; 149/73; 149/76; 149/77;
149/79; 149/94; 149/95; 149/96; 149/97; 149/110; 149/111; 149/112; 149/113; 149/114; 149/115
Intern'l Class:
C06B 045/02
Field of Search:
149/2,21,110-115,43,44,46,61,63,65,72,73,76,77,79,94,95,96,97

References Cited [Referenced By]

U.S. Patent Documents

3673286	Jun., 1972	Remaly et al.	149/110.
3725154	Apr., 1973	McCulloch et al.	149/110.
3986909	Oct., 1976	Macri	149/5.
3995559	Dec., 1976	Bice et al.	149/15.
4038112	Jul., 1977	Asaoka	149/110.

Primary Examiner: Lechert, Jr.; Stephen J.
Attorney, Agent or Firm: Brumbaugh, Graves, Donohue & Raymond

Parent Case Text

This application is a continuation-in-part of application Ser. No. 06/220975, filed 12/29/80, now abandoned.

Claims

We claim:

1. A solid or semisolid propellant comprising grains of propellant or propellant components bonded together so as to create voids within the propellant volume, said grains being of near-uniform size such that they have less than about a 20% size variation between the largest and smallest grains, said voids comprising from about 10% to about 50% of the propellant volume, said grains bonded together with sufficient strength to substantially delay the fluidization of the propellant by the onset of Taylor unstable burning, said propellant thereby having a rapid burn rate of from about 10 cm sec.sup.-1 to about 10.sup.4 cm sec.sup.-1.

2. A propellant according to claim 1 wherein said grains have less than about a 10% size variation between the largest and smallest grains.

3. A propellant according to claim 2 wherein said voids comprise from about 10% to about 20% of the propellant volume.

4. A propellant according to claim 3 wherein said grains are bonded together with a glue.

5. A propellant according to claim 4 wherein said glue also functions as a propellant or propellant component.

6. A propellant according to claim 5 wherein said glue is nitrocellulose.

7. A propellant according to claim 4 wherein said grains are black powder.

8. A propellant according to claim 4 wherein said grains comprise separate grains of oxidizer and grains of fuel.

9. A propellant according to claim 8 wherein said grains of oxidizer are selected from the group consisting of NH.sub.4 NO.sub.3, NH.sub.4 ClO.sub.3, NH.sub.4 ClO.sub.4, NaNO.sub.3, NaClO.sub.3, NaClO.sub.3, KNO.sub.3, KClO.sub.3 and KClO.sub.4 and said grains of fuel are selected from the group consisting of hydrocarbon and aluminum.

10. A propellant according to claim 3 wherein said grains are substantially spherical in shape.

11. A propellant according to claim 1 wherein said propellant grains are a monobase or double base propellant selected from the group consisting of nitrocellulose and nitrocellulose in combination with nitroglycerine.

12. A propellant according to claim 11 wherein said propellant grains are bonded together by bridges of said propellant, said bridges having been formed by the use of a solvent for the propellant that has first been permitted to partially dissolve the surface of the grains such that when the solvent is removed said grains are bonded together by bridges of said propellant.

13. A propellant according to claim 11 wherein said grains are bonded together by a glue, said glue comprising nitrocellulose which has been dissolved in a solvent, and wherein said solvent has been removed by drying after the grains are glued together.

14. A propellant according to claim 11 wherein the grains are bonded together with a glue that yields a high volume of inert gase when burned.

15. A propellant according to claim 14 wherein the glue is selected from the group consisting of polycarbonates and ureas.

16. A propellant according to claim 1 wherein said propellant is heterogeneous and comprises grains of NH.sub.4 NO.sub.3, polymerized Rubber and Aluminum.

17. A propellant according to claim 16 wherein said grains are bonded together with a glue, said glue selected from the group consisting of epoxy in combination with KClO.sub.4 and urethane in combination with KClO.sub.4.

18. A propellant according to claim 1 wherein said propellant has a burn rate of from about 10 cm sec to about 10.sup.3 cm sec.sup.-1.

19. A propellant according to claim 1 wherein said grains have a diameter of from about 0.5 cm to about 0.05 cm.

20. A propellant comprising grains of propellant or propellant components held within a fluid binder, said binder being sufficiently viscous so as to hinder the fluidization of the propellant volume by the onset of Taylor unstable burning and yet sufficiently fluid so as to permit the binder to flow during burning due to unequal stresses in the propellant volume and thereby to permit the surface shape of the propellant to continuously change during burning, said surface shape change during burning being sufficient to produce a burn rate of from about 10 m sec.sup.-1 to 100 m sec.sup.-1.

21. A propellant according to claim 20 wherein the binder is a petroleum oil.

22. A propellant according to claim 21 wherein the binder is selected from the group consisting of tar and bunker fuel oil.

23. A propellant according to claim 21 wherein the binder has a viscosity in the range between that of road tar and bunker C fuel oil.

24. A propellant according to claim 20 wherein the binder has a viscosity of at least 3000 poise.

25. A propellant according to claim 21 wherein at least some of the grains of propellant components are oxidizers.

26. A propellant according to claim 22 wherein at least some of the grains of propellant components are oxidizers.

27. A propellant according to claim 23 wherein at least some of the grains of propellant components are oxidizers.

28. A propellant according to claim 24 wherein at least some of the grains of propellant components are oxidizers.

29. A propellant according to claim 25 wherein at least some of the grains of propellant components are oxidizers selected from the group consisting of NH.sub.4 NO.sub.3, NH.sub.4 ClO.sub.3, NH.sub.4 ClO.sub.4, NaNO.sub.3, NaClO.sub.3, NaClO.sub.4, KNO.sub.3, KClO.sub.3 and KClO.sub.4.

30. A propellant according to claim 26 wherein at least some of the grains of propellant components are oxidizers selected from the group consisting of NH.sub.4 NO.sub.3, NH.sub.4 ClO.sub.3, NH.sub.4 ClO.sub.4, NaNO.sub.3, NaClO.sub.3, NaClO.sub.4, KNO.sub.3, KClO.sub.3 and KClO.sub.4.

31. A propellant according to claim 27 wherein at least some of the grains of propellant components are oxidizers selected from the group consisting of NH.sub.4 NO.sub.3, NH.sub.4 ClO.sub.3, NH.sub.4 ClO.sub.4, NaNO.sub.3, NaClO.sub.3, NaClO.sub.4, KNO.sub.3, KClO.sub.3 and KClO.sub.4.

32. A propellant according to claim 28 wherein at least some of the grains of propellant components are oxidizers selected from the group consisting of NH.sub.4 NO.sub.3, NH.sub.4 ClO.sub.3, NH.sub.4 ClO.sub.4, NaNO.sub.3, NaClO.sub.3, NaClO.sub.4, KNO.sub.3, KClO.sub.3 and KClO.sub.4.

33. A propellant according to claim 20 wherein said grains of propellant or propellant components are from about one micron to about one mm. in size.

Description

BACKGROUND OF THE INVENTION

The acceleration of rockets by the use of propellants is a well known technology. When propellants are used to accelerate vehicles into space, the rocket acceleration must be large compared to gravity (5 to 10 times g) so that impulse (force times time) is not wasted against gravitational force. When a rocket is in orbit or otherwise substantially uninfluenced by gravity the acceleration may be much smaller because gravity is no longer a limitation. Military rockets, on the other hand, must accelerate extremely rapidly, yet often the structure of the vehicle or the propellant composition limits the practical acceleration to a range of from 100 to 1000 g.

Rockets also find use in the rocket accelerated rod apparatus (RAR) such as is described in U.S. Pat. No. 3,509,821 for rapid penetration into dense media such as rock or metal. In RAR applications, an acceleration of several.times.10.sup.4 g is required if the rod is to be used for commercial applications of boring holes in rock or ground. The high acceleration is required so that the stand-off distance required for the rocket-rod to attain the required penetration velocity can be reasonably small, e.g. 10 meters. A typical velocity required for substantial penetration is approximately 2000 meters per second with the result that the acceleration (within a distance of about 10 meters) is approximately 20,000 g. Conversely, the time of acceleration of burning time of the propellant is very short, e.g. t=2 d/v.perspectiveto.10.sup.-2 seconds. Therefore there is a need for very fast burning propellants for rapid acceleration of projectiles for commercial uses.

In U.S. Pat. No. 3,616,855, which relates to the bulking and caving of underground ore bodies, a solid propellant is used to heave the ground after prestressing the formation by injecting an appropriate settable propping material. In such applications of earth fracturing (which is a form of bulking) there also exists a need for particular propellant burn properties. As discussed in U.S. Pat. No. 3,616,855, the propellant should burn (i.e. form the bulking or fracturing gas) in a time that is a small multiple (e.g. 2 to 10 times) of the dynamic time of the system. In this regard, it is not desired to shock the formation because this compacts the rock and wastes energy that would otherwise be used to lift it and form fractures. Fracturing with detonating explosives have shown that the shock wave in general compacts the ground or rock and does not in general open new fractures. While a slower gas release is thus desired, too slow a release results in the gas or fluid being lost into the formation. Hence the gas should be released within a period of approximately 2 to 10 times the dynamic time of the system.

A typical case is a well 3500 feet (1 km) deep. The time for a compression wave to reach the surface and return, i.e. the dynamic time, is roughly 2 seconds for a formation having a sound speed of 1 km sec.sup.-1. Hence the gas release time from a preferred fracturing or bulking propellant should be 5 to 10 seconds.

The placement of the propellant will be within the bore hole, for example a bore hole 8 inches in diameter and 1200 feet or 300 meters in length. The propellant must burn a length of 300 meters in 20 seconds, or a burn velocity of 15 meter sec.sup.-1. This also is in the range of burn velocity that is the objective of the present invention, but not available in conventional propellants.

There are thus two circumstances where a fast burning propellant is needed for useful purposes: fast rocket acceleration and underground well fracturing. In both cases the burn rate and hence the minimum pressure of the burning gases is roughly the same, namely several hundred MPA or 10 to 20 thousand PSI. This higher pressure is the result of the mass flow times gas velocity, or the time rate of change of momentum of the combustion gases. It is the useful pressure for either accelerating the rocket, or forcing the combustion gases into the rock for fracturing. Hence the high pressure of combustion is a necessary and useful result of a fast burning propellant. The magnitude of the pressure is determined by the geometry or confinement of the burn. It is this geometry or confinement that leads to two different mechanisms of fast burning propellants of this disclosure.

SUMMARY OF THE INVENTION

The propellants according to the present invention are solid propellants, since liquid propellants require pumps and plumbing. At high burn rates, pumps and plumbing become too massive.

The classical method for obtaining a fast burning solid propellant is to cast the solid propellant in a shape called a "grain" that has a large surface to volume ratio. A solid propellant burns at a rate dependent upon the pressure. This rate is proportional to:

(pressure).sup.gamma

where

gamma<1 for stable burn, and typically at a surface, gamma.about.1/2.

Hence one might think that merely going to very high pressure by the constriction of a nozzle would allow all desired burn rates. This is not true for two reasons:

(1) the required high pressure (e.g. 1000 atmospheres or 14,000 PSI) to obtain a typical burn rate of about 20 cm sec.sup.-1 with a conventional propellant would require a casing strength (and hence weight) far too great--e.g. equal to the propellant weight--for a useful rocket. Of course, even greater casing weights would be required if burn rates substantially in excess of 20 cm sec.sup.-1 and contemplated by the present invention (i.e. up to about 10.sup.4 cm sec.sup.-1) were to be obtained.

(2) Monopropellants do not have a constant factor gamma in the above equation and if pressure is high enough the desired burn or deflagration turns into a detonation of such high velocity that the rocket would be destroyed.

Thus both practical weight and burn instabilities prohibit normal stable fast propellant burn with conventional propellants. Therefore, as a practical matter, the fast burn rates achievable according to the present invention must be achievable with pressures not exceeding about 1000 atmospheres, and usually not exceeding a tenth of that.

Hence in current practice if one desires all the propellant to burn in a short time, one makes a large surface area with thin webs of propellant. Burning then proceeds from both sides of the thin web.

For example if the burn time is to be 10.sup.-2 seconds for a propellant that burns at 5 cm s.sup.-1, then the web thickness must be 1 mm. This is a thin web for a large rocket. This geometry, where the propellant is fluted in cross section, is also chosen such that the burning area remains roughly constant during the course of burning, so that the rate of production of combustion gases remains roughly constant.

If all the grain area is ignited at once, the burning will penetrate the webs rapidly and hence consume the propellant rapidly. The rocket casing and nozzle must confine the burn pressure. The nozzle converts the pressure to exhaust velocity and hence impulse.

The principal limitation of the thin webs of the standard grain geometry is the mechanical strength of the webs. If they are too thin, they cannot support the stress of the velocity of the high pressure combustion gases. The webs break and chunks of burning propellant are blown out the nozzle. This may choke the nozzle, lead to too rapid burn, and blow up the rocket. Hence there is a major requirement to produce a geometry for fast stable propellant burn.

The object of this invention is to disclose two geometries to achieve this objective: the first is end-burning of controlled size "chunks" of glued propellant, and the second is the controlled Taylor unstable burning of a viscous semi-solid semi-liquid propellant.

These two mechanisms relate to one another. Taylor instability comes about because of a differential pressure across a density discontinuity, i.e. the acceleration of a heavy fluid by a light one. In the case of propellant burn the combustion gases are the low density fluid and the propellant is the heavy fluid. The uncontrolled growth of a Taylor instability at a burning propellant surface leads to an uncontrolled increase of burning area and hence uncontrolled increase of pressure. This explodes the rocket casing. It may initiate detonation, i.e. converts propellant burn, a deflagration, to the explosive energy release of detonation. Hence uncontrolled Taylor instability growth is to be avoided for these purposes.

Taylor instability is damped by viscosity and prevented entirely by strength or rigidity of materials. The reason for solid propellants is to prevent the growth of Taylor instability at the burning surface. This disclosure is concerned with both the rigid case as well as the controlled growth of viscosity.

A rigid propellant is usually formed in a grain and the limit of burn rate is set by the thickness of the webs. Here we describe another method of obtaining a high burn rate using a rigid propellant. According to the invention, a propellant is provided which is comprised of near-uniform size particles--i.e. particles having less than about 20% size variation, and preferably less than about 10% size variation. By thus controlling the size variation of the respective particles, the size of the voids created when the particles are glued together (e.g. as by gluing them over approximately 20% of their surface area) are likewise controlled and of near-uniform size. Depending upon the shape and size of propellant particles chosen, the void size can be easily controlled and a void volume of from 10% to 50% of the total propellant volume can be maintained.

In one typical case the particles in a useful example are 0.2 cm (2 mm) diameter spheres glued over 20% of their surface area. The resulting glued structure results in a very strong rigid matrix. The matrix is so strong that the high pressure of burning does not crush the matrix. Instead it stably supports a high pressure--pressures of several hundred MPA, 10,000 to 20,100 PSI. Hence once the glued structure is ignited, the burn front progresses through the structure without breaking or crushing the propellant. The ignition of the structure starts at a surface and the controlled, near-constant size of the interconnected voids between particles allows the burning gas to propagate the ignition flame into the matrix. This flame progression is controlled by both the tortuosity of the surface area and by the voids between particles or spheres of propellant. By properly controlling the ignition properties, the void size, and the grain size, the flame front speed in the matrix can be controlled and hence the ignition rate of the matrix. The grain must be consumed in the time the flame front passes by. Hence the grain size must be controlled as well as the void size.

A given grain must be consumed in the time for the flame front to propagate the flame front's own width. Hence the size of the grain is determined by the propellant's burn properties, void spaces and flame propagation. Typically the burn velocity is 100 to 1000 cm sec.sup.-1. The solid propellant burn rate might be 5 cm sec.sup.-1 at the burn pressure determined by the nozzle area.

The flame front width is determined by the void spaces and ignition properties and typically might be about 5 cm. Thus the burn time per grain might be 0.05 to 0.005 seconds. Therefore the grain radius would be 0.25 to 0.025 cm (0.5 to 0.05 cm diameter). The 0.2 cm diameter spheres referred to above fall within this range. The result is a fast burning propellant where the burn front is a finite thickness or penetration into the structure.

It is important to note in this regard that the present invention differs from previously known sponge or foam compositions. Such sponge or foam compositions normally contain voids of non-uniform size which comprise from 95% to 98% of the propellant volume, and as such are known to burn at an uncontrolled rate substantially faster than that contemplated by the present invention. While such compositions perform satisfactorily as ignitors for other higher density propellants, they lack the density (and hence the ability to provide sufficient impulse) and controlled burning characteristics (due to the lack of strength of the foam and the wide disparity in particle size and void size) required of a true propellant.

The second method of making a fast burning propellant is to control the viscosity of the solid propellant. Viscosity determines the rate of Taylor unstable growth and hence determines the rate of new area of the burning front. Viscosity stabilizes small wave lengths and prevents them from growing. For a given viscosity, surface acceleration, and density ratio only wave lengths larger than a given size will grow. If the lateral extent of the burning front were infinite, then larger wave lengths could grow and the area of burning could increase without limit. On the other hand if the propellant is confined in a tube of diameter D, then the largest wave length that can grow is limited to D.

Hence if the largest wave length that can grow is the diameter, and the growth of smaller wave lengths is limited by viscosity, a combination can be chosen such that the rate of production of new area by Taylor instability is limited.

As noted above, the phenomona known as Taylor unstable burning occurs when a heavy fluid is accelerated by a light fluid and an instability takes place at the interface whereby the light fluid interpenetrates the heavy fluid with "fingers" of penetration (e.g. as will occur if one attempts to support water with air). If the density difference is large, the depth of penetration is a fraction of (e.g. 1/3) the distance the whole mass moves during acceleration. In the usual rocket the hot (light) exhaust gases push on the high density propellant. The only reason these two systems do not mix by Taylor instability is that the heavy meterial, the propellant, is semirigid and does not "flow" like a fluid.

However, it has been found that there is a more rapid burning of solid propellant when no binder is used in a conventional solid propellant mixture so that the mixture of, for example, KClO.sub.4 and Aluminum is "fluidized" by the reacting gases and fingers of flame penetrate into the propellant. This has the result of causing a much faster overall burn of the fuel. The problem with this mode of propellant burn is that it is too fast and approximates an uncontrolled deflagration. It has been found that the Taylor unstable mixing progresses into the propellant at a fraction (.ltoreq.1/10) of the sound speed of the propellant cumbustion gases. (These experiments were performed with powdered propellants.) Since the sound speed is large C.sub.s .ltoreq.1.5.times.10.sup.3 m sec.sup.-1, the resultant burn velocity 1 to 2.times.10.sup.2 m sec.sup.-1 is too great for practical use. This rapid burn generates too high a pressure (about 10.sup.4 atmospheres, 140,000 PSI) for the feasible structural strength of any rocket casing.

We demonstrate our understanding of the phenomena by calculating the above experimental result. One can calculate the expected burn rate in Taylor unstable burning by assuming that the Taylor instability occurs only when the in situ burning has proceeded far enough to fluidize the propellant by generating enough high temperature gas
to fill the interstices to a pressure equal to or greater than the free surface pressure of the burn front. This fluidized propellant then allows Taylor unstable mixing to occur at a mean velocity that is a fraction, e.g. 1/2 to 1/3, of the combined (propellant solids and fluidizing gas) sound speed of the mixture. If the mass fraction of the burn necessary to reach this pressure is f.sub.mass, then the combination sound speed of the mixture becomes

C.sub.mix =C.sub.s f.sub.mass.sup.1/2

The sound speed of the mixture is increased proportionally to the square root of the increase in the effective density of the mixture. If f.sub.mass equals 1/10, then the burn rate, R, becomes

R.perspectiveto.1/3C.sub.mix

On the other hand the burn rate R leads to a pressure P.sub.burn for a free surface burn, i.e. without a nozzle, of

P.sub.burn =R.rho.v.sub.exhaust

where v.sub.exhaust .congruent.the specific impulse times g which is the velocity corresponding to the conversion of the internal energy to kinetic energy. .rho.=density of propellant. Therefore ##EQU1## On the other hand the fraction of propellant that must be burned to reach a given pressure in the interstices (i.e. void volume) of a heterogeneous propellant of fractional void volume f.sub.void (assumed small) becomes ##EQU2## Here, if the void volume were 1%, then the mass fraction, f.sub.mass, that would have to be burned to reach a pressure P.sub.burn equal to the maximum confined pressure .rho.C.sub.s.sup.2 /.gamma., would be also 1%. Thus ##EQU3## For typical values of a propellant of KClO.sub.4 and powdered aluminum, C.sub.s .perspectiveto.1/2v.sub.exhaust .perspectiveto.1.2.times.10.sup.3 m sec.sup.-1, .gamma..congruent.1.4 so that ##EQU4## For a fairly wide distribution of particle size, f.sub.void =20% so that R.perspectiveto.2.times.10.sup.2 m sec.sup.-1. This is just in the range observed. This results in too large a pressure for practical application, .perspectiveto.7500 atmospheres, or 110,000 PSI.

The fastest solid propellants burn at about 0.1 m sec.sup.-1 while Taylor unstable burning burns at a rate approximately 10.sup.3 times faster. It is thus the object of this invention to provide a means to control the burn rate of a solid or semisolid propellant to values intermediate between these extremes i.e. from 10 to about 10.sup.4 cm sec.sup.-1 and preferably from about 10 to about 10.sup.3 cm sec.sup.-1. This is accomplished according to either of two preferred embodiments, one of which prevents the onset of Taylor unstable burning by forming a rigid strong matrix of glued, near-constant size particles or chunks, the other of which imposes a velocity limitation in the nonlinear phase of Taylor instability growth.

Looking to the first embodiment, a conventional powder propellant when packed together yields a structure of mass which contains voids, typically comprising from 10% to 50% of the volume of the structure or mass. As pointed out above, it is the flow of gas through the interstices of the inter-grain void spaces that allows the "fluidization" of the propellant and the very rapid Taylor unstable burn. In this regard, it is important to note that with respect to conventional solid propellants, voids are purposely carefully eliminated for this very reason, i.e. voids will normally permit the onset of Taylor instability.

According to the present invention, however, the voids are retained (preferably comprising from 10% to 20% of the propellant volume), but one grain is glued rigidly to the next so that the fluidization process cannot take place. Thus the Taylor unstable burning mode also cannot take place. Gas will flow to a limited extent between the grains, but the large increase in the area of unstable burning will not take place--unless and until the glue strength disappears due to melting or burning of the glue. The thicker the glue bond, grain to grain, and the more refractive the glue, then the longer it will take for the grain to become free and enter the fluidized fraction of the propellant. In other words the stronger the glue the slower the burn. The slowing down of the burn rate below that associated with free particle Taylor unstable burn is desired.

As pointed out above, foamed propellants such as are used for fast ignition will not work as a fast propellant, one because the density is so low that only a very small mass of propellant is possible inside a casing, and secondly the strength of the foam is too small or weak to support high pressure, high stress rapid burn, and third the velocity of burn is uncontrollably high due to the wide dispersion in particle size.

The second embodiment differs from the first in that the "glue" is a viscous fluid, such as a heavy oil, which fills the voids between the grains. This viscous fluid serves not to delay the actual onset of Taylor instability (such as is imposed by the time it takes the glue to lose strength by melting or burning), but instead permits the continuous surface changes during burning normally associated with Taylor instability but at a substantially slower rate (i.e. as mentioned above a velocity limitation is imposed upon the nonlinear phase of Taylor instability growth rate due to the viscosity and shear stress of the fluid). With respect to this second embodiment, a burn rate of from about 10 to about 10 m sec.sup.-1 is preferred.

Unlike the first embodiment of the invention, wherein substantially uniform particle size is important, the second embodiment permits the particle size to vary substantially. Typical particle diameters resulting from conventional manufacturing methods and usable in the present invention range from about one micron to about one mm.

This second embodiment is particularly useful in well fracturing because the large quantity of propellant that must be used calls for a relatively low cost propellant. In addition, because the propellant is placed at great depth, considerable pressure compacting of the propellant may occur due to the length of the column as well as fluid pressures. Hence it may be impractical to use void-containing propellants that are glued particle to particle such as are contemplated by the first embodiment.

DESCRIPTION OF EXEMPLARY EMBODIMENTS

EXAMPLE 1

Cracked black powder grains were screened to 1/16 to 3/32 inch size such that the grain size distribution was relatively narrow--i.e., a size distribution to within 50%.
The grains were then coated with a glue that also functions as a propellant. The glue was made by dissolving a high nitrogen nitrocellulose, i.e., 12 to 12.5% nitrogen, in a solvent such as acetone, ether, or ether alcohol. In initial trials, the mass fraction of combustible glue was roughly 5 to 10% although other percentages will give different burn rates. The coated grains were then packed in an open end tube--a rocket casing 10 cm long--and allowed to dry (i.e. the solvent of the glue was allowed to evaporate). When the dried and cured propellant was ignited, it burned stably in about a tenth of a second. This gives a burn rate of 100 cm sec.sup.-1. A smaller mass fraction of glue--say 1%--increases this burn rate by another factor of 10. If a heterogeneous propellant like NH.sub.4 ClO.sub.4 or KClO.sub.4 plus Aluminum is used,
the glue can take the form of a combustible hydrocarbon such as epoxy or urethane. The ratio of glue to aluminum to oxidizer should be such as to create a

stoichiometric balance for highest performance although a slower burn rate may require a compromise of performance. It will also be appreciated by one skilled in the art that other common oxidizers may be used according to the invention such as the compounds having Na, K, and NH.sub.4 as the cation and NO.sub.3, ClO.sub.3 and ClO.sub.4 as the anion.

EXAMPLE 2

In another embodiment the monobase or double base powders (Nitrocellulose or nitrocellulose plus nitroglycerine) may be pre-formed into balls all accurately the same size, or more complicated shapes, grains, as is well known in military cannon technology. The simplest shape, called ball powder, is ideally suited to the present concept of a controlled fast-burning propellant. A ball powder can be made of a predetermined cut of different size balls so that different packing fractions are achieved, i.e. different ratios of void space to propellant space. In addition the maximum ball size determines the burn rate as an additional delay time to the glue melting time. In this case the glueing of such a matrix is relatively simple. In one case the prepacked powder can be wetted with a solvent like ether or acetone or other well known solvent for nitrocellulose and the solvent allowed to partially dissolve the grains, e.g. balls, for a predetermined length of time. The solvent is then allowed to drain out and the dissolved surfaces of the grains then act as their own glue.

The subsequent evaporation of the solvent from within the volume of the propellant is facilitated by the fact that the void space interconnects the whole volume and hence air transport of the solvent can readily take place.

Alternately, for slower burning of the same propellant at a high chamber pressure, for example greater than 1000 PSI, it may be desirable to use a thicker glue layer filling 1/2 the void space. Then the balls should be precoated with glue before packing. The glue in this case preferably is a propellant also so that it adds to the reactive mass. Again nitrocellulose dissolved in solvent is an advantageous choice. However there may be circumstances where high specific impulse may not be the only consideration, but instead a high volume of gas may be desired. Then a glue that gives a high volume of inert gas when heated such as polycarbonates or ureas could be advantageously used.

EXAMPLE 3

The particular advantage of heterogeneous propellants where oxidizer and fuel are physically separated in the matrix--such as NH.sub.4 NO.sub.3, Thiokol rubber, and aluminum--is that they are much safer to handle and transport and are considered practically immune to detonation. Accidental ignition is however possible and, while not necessarily as catastrophic as a detonation, is nonetheless serious. Hence, there is a need to make safer very fast burning heterogeneous propellants. Again the heterogeneous propellant can be preformed into grains and then the grains glued to one another in a fashion entirely analagous to the homogeneous propellants. The standard heterogeneous propellant that uses a polymerized rubber, for example Thiokol, is not as easily dissolved in place as nitrocellulose, and so the preferred embodiment in this case requires that a glue be added to the grains before casting. Again the pre-polymerized rubber combined with fuel (aluminum) is one choice but many self-polymerizing glues with oxidizers added like epoxy and KClO.sub.4 or urethane and KClO.sub.4 are feasible.

EXAMPLE 4

In this example the propellant is considered to be a heterogeneous mixture that is fluidized with a viscosity .eta.. The scale of the heterogenity is the grain size .delta. of oxidizer or oxidizer-fuel grains. The instability growth is already initiated at large amplitude by the different properties of density and temperature of the burning grain boundaries and the viscous fluid. If the burn pressure is P, then the differential acceleration, .DELTA.a, will be of the order ##EQU5## where .rho. is the average density and .DELTA..rho. the density difference between grains and fluid. The differential acceleration will be balanced by a shear stress from the velocity gradient, (.DELTA.v/.delta.) in the viscous fluid of viscosity .eta..

The viscosity shear stress is approximately 2.eta.(.DELTA.v/.delta.) so that balancing of forces yields

(.DELTA.a) .rho.=2.eta.(.DELTA.v/.delta.)

or ##EQU6## Choosing typical values, the typical grain size of the cheapest commercial oxidizer, NaNO.sub.3, is .delta..perspectiveto.1 mm. The density contrast between the cheapest viscous fluid fuel, i.e. petroleum oils and tars, and NaNO.sub.3 is .DELTA..rho./.rho..perspectiveto.1/3. The typical pressure required for fracturing a well 1 km deep would be 300 atmospheres. Then the intergrain or instability flow velocity would be

.DELTA.v.perspectiveto.5.times.10.sup.4 /.eta. meters sec.sup.-1.

This formula of course does not hold unless .eta. is quite large such that .DELTA.v is much less than sound speed, e.g. .DELTA.v<<2.times.10.sup.3 meter sec.sup.-1. Otherwise the assumption of neglecting inertial forces in favor of viscous forces would not apply. However, because a relatively slow speed (compared to sound speed) of .DELTA.v.perspectiveto.10 to 20 meter sec.sup.-1 is desired, a viscous fluid binder or fuel of .eta..perspectiveto.3000 poise will be necessary. Since SAE 50 automotive oil has a viscosity at 100.degree. F. of roughly 1/10 this value (260 poise) it can be seen that the viscous fluid should have a viscosity between a typical road tar and bunker C fuel oil. This is fortunate because for the proposed use these residual oils are the least expensive.

Therefore a typical embodiment of a viscous solid propellant for oil well fracturing or underground bulking could combine the cheapest oxidizer NaNO.sub.3 blended with a residual oil such as to form the products NaO+N.sub.2 +H.sub.2 O+CO.sub.2. In addition, in order to ensure burning of the relatively refractory oxidizer NaNO.sub.3, one can increase the flame temperature by the addition of powdered Aluminum or a similar high energy fuel. In this case, depending upon the stoichiometric fraction, some of the heavy oil will be just vaporized rather than burned. The effectiveness of this vaporized oil as a fracturing gas is comparable to the combustion product gases. This then becomes a preferred mixture.

If the heavy oil has a low value of H to C of .congruent.1, then an excess of fuel may yield less oxygen and the products CO, CO.sub.2 and H.sub.2. This is slightly preferred in fracturing because the steam (H.sub.2 O) will give up its heat to fractures and liquefy to water, thereby reducing the useful gas volume for fracturing.

EXAMPLE 5

The limiting viscosity of a viscous binder is a solid. Coal will not re-form with heat, but as a pulverized solid it can give a fast burning rate as a powder depending on particle size. The natural bitumen "Gilsonite" has the peculiar properties that it can be ground as a solid, but then partially reformed as a plastic and so a variable degree of binding can be achieved between oxidizer and fuel particles. This also can lead to medium to fast burning rate propellant just as the glued grain example.

EXAMPLE 6

A typical embodiment of well fracturing with a fast burning propellant starts with the completion of a well, for example 8" in diameter although larger or smaller diameters are entirely feasible. The volume of propellant to be burned is determined by the desired fracture system. Typically volumes of very large fracture or stimulation operations are of the order of 10,000 barrels or 2000 cubic meters. A gasified solid propellant expands to a volume of roughly 100 times the propellant volume to a typical formation pressure of 200 atmospheres (3000 PSI).

The energy content of the propellant is roughly 5.times.10.sup.10 ergs/gm giving rise to a pressure of .perspectiveto.10.sup.11 dynes cm.sup.-2. The adiabatic expansion of the propellant gases from 10.sup.11 dynes to 200 atmospheres, or 2.times.10.sup.8 dynes cm.sup.-2, results in a volume change of (10.sup.11 /2.times.10.sup.8).sup.1/.gamma. .perspectiveto.85 fold. Since the density of the propellant is somewhat greater than unity, the volume of gases should be roughly 100 times the volume of propellant. The expansion of the gases may not be entirely adiabatic depending upon the back pressure in the burning region. However, if the expansion is at constant enthalpy, the volume of gas will be greater up to the ratio V.sub.1 /V.sub.2 =P.sub.1 /P.sub.2 .perspectiveto.500. Hence the adiabatic approximation is the lower limit of available fracture volume.

In the above circumstances, the initial propellant charge of 10 m.sup.3 should be the equivalent of 1000 m.sup.3 or 5000 barrels of pumped fracture fluid.

Next a string is set with an igniter at the base (preferably Thermite or other high temperature burning igniter) and with the maximum diameter that will go down the hole--e.g. 8" in the present example. The strength of the string must be great enough to contain the propellant in place. In this example L=Vol/area.perspectiveto.300 meters assuming a pipe string wall thickness of 1/4", enough to hold the added fracture pressure during the transient burn period and assuming a competent formation as backup of the well liner. The top of the string can be closed off with a packer or stemmed with a weak cement or sand if later drill back is expected. The advantage of the weak cement or sand stem is that in the event of a blow-out from unforeseen reasons the propellant and cement particles could vent to the surface with lessened danger to personnel in the immediate vicinity.

The propellant is mixed down hole with preheated viscous oil and oxidizer. In this regard, NaNO.sub.3 is preferred as it is the cheapest oxidizer. By mixing down hole, one avoids the danger of preignition and possible danger to personnel.

EXAMPLE 7

In a less preferred embodiment, one might consider pumping the propellant slurry through a nozzle down hole during burning at a velocity sufficiently great so that the burn front does not climb up the injection string. In this way one could avoid the difficulty of setting a casing string, and instead use cheaper, smaller diameter tubing.

However, certain difficulties can be foreseen with this approach. First, by the previous analysis the viscosity of the oil must be low for rapid pumping, yet high in order to control the burning rate of the propellant. The high viscosity of 3000 poise essentially precludes rapid pumping because of viscous pipe losses. A lower viscosity will give too high a burn rate. Finally if a slurry of pre-mixed fuel and oxidizer is pumped at a high pressure, there is always the danger of ignition by friction in the pump valves and piping. This could lead to an explosion. Hence the propellant is preferably mixed in the relative safety of down hole and burned in situ.

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United States Patent **6,439,310**

Scott, III , et al. **August 27, 2002**

Real-time reservoir fracturing process

Abstract

Methods are disclosed for hydraulic fracturing of subterranean reservoir formations using various combinations of gelled fluid, nitrogen, and carbon dioxide base components, in association with proppant and other additives. Selected base components are pumped down a wellbore tubing while other selected base components are simultaneously pumped down the wellbore tubing-casing annulus for downhole mixing into a composite fracturing fluid in the downhole region of the wellbore proximal to the reservoir objective. Thereby, changes may be timely effected in the composite fluid composition and fluid properties, substantially immediately prior to the composite fluid entering the formation. Such real-time modifications may be effected to readily preempt screenout occurrences and may facilitate composite fluid compositions which otherwise are frequently undesirable to pump from the surface. Such composite fluid combinations include components phases of each of carbon dioxide, nitrogen and a base fluid. Proppant concentrations within the composite fluid entering the formation may be effected in real time without the wellbore-volume lag-time inherent in prior art methods.

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Parent Case Text

This application claims priority from U.S. provisional application 60/232,717 filed Sep. 15, 2000.

The invention described herein in part was made in the performance of work supported by the U.S. Department of Energy. Thereby, the U.S. Government has certain rights in the invention.

Claims

What is claimed:

1. A method of hydraulically fracturing a subterranean formation penetrated by a wellbore, at least a portion of the wellbore including a tubing string having a tubing bore and a casing string, the casing string and tubing string forming a casing annulus, a portion of the well bore not including the tubing string therein forming a casing bore, the method comprising:

injecting carbon dioxide into the wellbore via one of the tubing bore and the casing annulus at a first injection flow rate;

simultaneously injecting nitrogen into the wellbore via the other of the tubing string and casing annulus at a second injection flow rate;

simultaneously injecting an aqueous fracturing fluid into the wellbore with at least one of the carbon dioxide and nitrogen, at a third injection flow rate;

combining the carbon dioxide, the nitrogen and the aqueous fracturing fluid in the casing bore to form a downhole mixed composite fracturing fluid having a mixed fluid composition;

injecting the downhole mixed composite fracturing fluid from the casing bore into the subterranean formation at a hydraulic pressure sufficient to hydraulically fracture the formation; and

selectively varying one or more of the first injection flow rate, the second injection flow rate, and the third injection flow rate to modify in real time the mixed fluid composition of the downhole mixed composite fracturing fluid, forming a modified downhole mixed composite fracturing fluid.

2. The method as defined in claim 1, further comprising:

adding a solid material proppant to the aqueous fracturing fluid to form a proppant laden downhole mixed composite fracturing fluid having another mixed fluid composition; and

thereafter injecting the proppant laden downhole mixed composite fracturing fluid from the casing bore into the subterranean formation at hydraulic pressures sufficient to hydraulically fracture the formation.

3. The method as defined in claim 2, further comprising:

selectively varying one or more of the first injection flow rate, the second injection flow rate, and the third injection flow rate to modify in real time the another mixed fluid composition of the proppant laden downhole mixed composite fracturing fluid.

4. The method as defined in claim 2, wherein a quantity of proppant in the proppant laden downhole mixed composite fracturing fluid is selectively adjusted in real time by varying at least one of the first injection flow rate, the second injection flow rate, and the third injection flow rate.

5. The method as defined in claim 2, further comprising:

monitoring in real time within the well bore a location in the formation of at least one radioactive tracer provided in at least a portion of one or more of the downhole mixed composite fracturing fluid and the proppant laden downhole mixed composite fracturing fluid by monitoring radioactive emissions from the at least one radioactive tracer; and

varying at least one of the first injection flow rate, the second injection flow rate, and the third injection flow rate in response to the monitored radioactive emissions.

6. The method as defined in claim 1, further comprising:

while selectively varying one or more of the first injection flow rate, the second injection flow rate and the third injection flow rate, increasing a viscosity of the modified downhole mixed composite fracturing fluid as compared to the downhole mixed composite fracturing fluid and cause viscous inter-fingering of the modified downhole mixed composite fracturing fluid within the downhole mixed composite fracturing fluid within the subterranean formation.

7. The method as defined in claim 1, further comprising:

adding to the aqueous fracturing fluid a selected amount of one or more additives from a group comprising chemical additives, gelling agents, alcohols, salts, fluid loss additives, and encapsulated additives; and

selectively varying the selected amount of the one or more of additives added to the aqueous fracturing fluid in response to selectively varying one or more of the first injection flow rate, the second injection flow rate and the third injection flow rate.

8. The method as defined in claim 1, further comprising:

adding a cross-linkable gelling agent to at least one of the carbon dioxide, the nitrogen and the aqueous fracturing fluid; and

adding a cross-linking agent to another of the carbon dioxide, the nitrogen, and the aqueous fracturing fluid such that the cross-linkable gelling agent and the cross-linking agent mix downhole in the casing bore in the composite fracturing fluid and cross-link at least a portion of the cross-linkable gelling agent.

9. A method of hydraulically fracturing a subterranean formation penetrated by a wellbore, at least a portion of the wellbore including a tubing string having a tubing bore and a casing string, the casing string and tubing string forming a casing annulus, a portion of the well bore not including the tubing string therein forming a casing bore, the method comprising:

injecting an aqueous fracturing fluid down one of the casing annulus and the tubing bore at a first injection flow rate;

simultaneously injecting an energized fluid down the other of the casing annulus and the tubing bore at a second injection flow rate;

combining the energized fluid and the aqueous fracturing fluid in the casing bore to form a first downhole mixed composite fracturing fluid having a first mixed fluid composition;

injecting the first downhole mixed composite fracturing fluid from the casing bore into the subterranean formation at a hydraulic pressure adequate to fracture the formation; and

selectively varying one or more of the first injection flow rate and the second injection flow rate to modify in real time the first mixed fluid composition of the first downhole mixed composite fracturing fluid to form a second downhole mixed composite fracturing fluid.

10. The method as defined in claim 9, further comprising:

adding a solid material proppant to the aqueous fracturing fluid to form a proppant laden downhole mixed composite fracturing fluid having a second mixed fluid composition; and

thereafter injecting the proppant laden downhole mixed composite fracturing fluid from the casing bore into the subterranean formation at hydraulic pressures sufficient to hydraulically fracture the formation.

11. The method as defined in claim 10, wherein a quantity of proppant in the composite fracturing fluid is adjusted in real-time by varying at least one of the first injection flow rate and the second injection flow rate.

12. The method as defined in claim 10, further comprising:

selectively varying one or more of the first injection flow rate and the second injection flow rate to modify in real time the second mixed fluid composition.

13. The method as defined in claim 10, further comprising:

monitoring in real time within the well bore a location in the formation of at least one radioactive tracer provided in at least a portion of one or more of the downhole mixed composite fracturing fluid and the proppant laden downhole mixed composite fracturing fluid by monitoring radioactive emissions from the at least one radioactive tracer; and

varying at least one of the first injection flow rate and the second injection flow rate in response to the monitored radioactive emissions.

14. The method as defined in claim 9, wherein the energized fluid further comprises:

at least one of carbon dioxide and nitrogen.

15. The method as defined in claim 9, further comprising:

while selectively varying one or more of the first injection flow rate and the second injection flow rate, increasing a viscosity of the second downhole mixed composite fracturing fluid as compared to the first downhole mixed composite fracturing fluid and cause viscous inter-fingering of the second downhole mixed composite fracturing fluid within the first downhole mixed composite fracturing fluid, within the subterranean formation.

16. The method as defined in claim 9, further comprising:

adding a gelling agent to one of the aqueous fracturing fluid and the energized fluid; and

adding a cross-linking agent to the other of the aqueous fracturing fluid and the energized fluid, such that the gelling agent and the cross-linking agent mix downhole in the casing bore.

17. A method of hydraulically fracturing a subterranean formation penetrated by a wellbore, at least a portion of the wellbore including a tubing string having a tubing bore and a casing string, the casing string and tubing string forming a casing annulus, a portion of the well bore not including the tubing string therein forming a casing bore, the method comprising:

injecting a first aqueous fracturing fluid including a cross-linkable gelling agent down one of the casing annulus and tubing at a first injection rate;

injecting a second aqueous fracturing fluid including a gel cross-linking agent down the other of the casing annulus and the tubing at a second injection rate;

combining the first aqueous fracturing fluid and the second aqueous fracturing fluid in the casing bore to form a downhole mixed composite fracturing fluid having a first mixed fluid composition;

injecting the downhole mixed composite fracturing fluid from the casing bore into the subterranean formation at pressures sufficient to hydraulically fracture the formation; and

selectively varying one or more of the first injection flow rate and the second injection flow rate to modify in real time the first mixed fluid composition of the downhole mixed composite fracturing fluid.

18. The method as defined in claim 17, further comprising:

adding a solid material proppant to one or more of the first aqueous fracturing fluid and the second aqueous fracturing fluid to form a proppant laden downhole mixed composite fracturing fluid having a second mixed fluid composition; and

thereafter injecting the proppant laden downhole mixed composite fracturing fluid from the casing bore into the subterranean formation at pressures sufficient to hydraulically fracture the formation.

19. The method as defined in claim 18, further comprising:

varying at least one of the first injection flow rate and the second injection flow rate to selectively modify in real time at least one of a physical property and a chemical property of at least one of the first mixed fluid composition and the second mixed fluid composition.

20. The method as defined in claim 19, wherein selectively adjusting in real time at least one of a physical property and a chemical property further comprises:

selectively varying a viscosity physical property to cause viscous inter-fingering of fluids in the subterranean formation.

21. The method as defined in claim 18, wherein a quantity of proppant in the proppant laden downhole mixed composite fracturing fluid is selectively adjusted in real time by varying at least one of the first injection flow rate and the second injection flow rate.

22. The method as defined in claim 17, further comprising:

monitoring in real time within the well bore a location in the formation of at least one radioactive tracer provided in at least a portion of one or more of the downhole mixed composite fracturing fluid and the proppant laden downhole mixed composite fracturing fluid by monitoring radioactive emissions from the at least one radioactive tracer; and

varying at least one of the first injection flow rate and the second injection flow rate in response to the monitored radioactive emissions.

23. The method as defined in claim 17, further comprising:

injecting an energizing fluid comprising one or more of carbon dioxide and nitrogen with one or more of the first aqueous fracturing fluid and the second aqueous fracturing fluid.

Description

ORIGIN OF THE INVENTION

1. Field of the invention

This invention relates to hydraulic fracturing in petroleum and natural gas reservoirs, and more particularly to real-time modification thereof by downhole mixing of fracturing components.

2. Background of the Invention

A typical reservoir ***stimulation*** process involves hydraulic fracturing of the reservoir formation and proppant placement therein. The fracturing fluid and proppant are typically mixed in pressurized containers at the surface of the well site location. This surface-mixed composite fracturing fluid is generally comprised of an aqueous fracturing fluid, proppant, various chemical additives, including gel polymers, and often energizing components such as carbon dioxide (CO2) and nitrogen (N2). After adequate surface mixing, the composite fracturing fluid is pumped via high-pressure lines through the wellhead and down the wellbore, whereupon ideally the fluid passes into the reservoir formation and induces fractures. Successful reservoir ***stimulation*** fracturing procedures typically increase petroleum fluid and gas movement from the fractured reservoir rock into the wellbore, thereby enhancing ultimate recovery.

Reservoir ***stimulation*** procedures are capital intensive. Implementation difficulties arise with many known ***stimulation*** methods due to various problems, including limitations associated with surface mixing of the ***stimulation*** fluid. Typically, a viscous, surface-mixed composite ***stimulation*** fluid is injected at pressures adequate to create and propagate fractures in the reservoir. The pressures required to pump such ***stimulation*** treatments are relatively high, particularly during injection of the gelled, thickened fluids that may be used to propel proppant into the fractures. These pumping pressures often will increase during the treatment process to an excessive limit, whereupon the operator promptly and prematurely terminates the treatment. Otherwise, serious problems may result, including rupture of surface equipment or wellbore casing and tubulars.

Excessive treating pressures may also occur abruptly during the ***stimulation*** fracturing process as a result of premature screenout. Such screenouts are a common problem known in industry that may occur during a fracturing treatment when the rate of ***stimulation*** fluid leakoff into the reservoir formation exceeds the rate in which fluid is pumped down the wellbore, thus causing the proppant to compact within the fracture, and into the wellbore. This problem of premature screenout is discussed in U.S. Pat. No. 5,595,245, which is hereby incorporated by reference.

When premature screenout is observed during a fracturing treatment, the operator may elect to reduce the proppant quantity, density, or concentration of proppant per volume of fluid, in order to prevent the occurrence of the screenout. However, when the reduction in proppant concentration is made at the surface, a significant amount of time typically passes before the pumped fluid with altered proppant concentration actually reaches the formation.

A potential problem associated with surface-blended composite fluids is that inhibitors are required to prevent viscous gelling of the ***stimulation*** fluid prior to pumping downhole. Highly viscous gels are typically desirable for effective transport of proppant, however, if viscous gelling occurs too early, such as in the tanks and flowlines, or before the fluid is pumped down the well, the efficiency of the overall ***stimulation*** job may be compromised due to higher pressures and lower pump rates. To avoid premature gelling, various known chemical inhibitors that include encapsulated or chemically coated inhibitors may be mixed into the composite fluid mixture at the surface to provide a time delayed gelling of the composite fracturing fluid. In addition, other known additives may be incorporated at the surface in an attempt to predictably control the rate of gelling, such as inhibitors to time-delay activation of cross linked polymer gels, which prevents premature gelling of the composite fracturing fluid. A serious shortcoming of this surface-mixed approach, however, is either gelling too early, or too late as evidenced by inadequate gel quality, which frequently results in poor proppant transport and premature screenout.

Typically in many wells the fracturing treatments are terminated prematurely, or reduced in size due to excessive pumping pressures that result from surface mixed and pumped fracturing treatments. In older wells, the premature gelling of the composite fracturing fluid creates a significant potential of exceeding the rated casing or tubing burst pressure.

In a 12,000 feet well, for instance, surface wellhead treating pressures often exceed 10,000 psi. whereas bottomhole treating pressures at the reservoir formation depth are significantly higher due to the combination of hydrostatic weight of the composite fracturing fluid (in wellbore) plus surface pumping pressures and friction pressure. The resultant bottomhole treating pressures, if excessive, may crush or fracture proppants in the fracture, which is undesirable due to the release of fines, fracture closure and overall formation damage.

Higher treating pressures are detrimental in terms of requiring lower pump rates, and thereby often alter the overall fracturing ***stimulation*** design at the well site. Frequently, the volumetric amount of composite fracturing fluid and proppant that are pumped is lower than desired due to restricted pump rates. Typically higher pumping pressures result in larger horsepower requirements, the usage of more pump engines, and higher cost. Reservoir ***stimulation*** fracturing is a capital intensive process, and ineffective reservoir ***stimulation*** treatments result in a significant loss of both expended capital and the potential recovery of hydrocarbon reserves.

A typical industry fracturing procedure may commence with mixing of the composite fracturing fluid in storage tanks located on the surface at the well site. The composite fracturing is typically comprised of aqueous gelled fluid, chemical additives and energizers such as N2 and CO2. After mixing, the composite fracturing fluid is pumped via high-pressure lines through the wellhead, down the wellbore and injected into the induced formation fractures. The pumping procedure is typically initiated with the pumping of a pad stage, which is typically fluid without proppant, followed by various stages of fluid containing proppant, and upon termination of the proppant-laden fracturing stage by pumping of the flush stage, which is generally fluid without proppant. This aforementioned sequence occurs when the treatment is pumped as designed, and in the absence of problems including excessive treating pressures and premature screenout.

Another typical industry ***stimulation*** technique is known in industry as hydraulic notching or "hydrajetting", whereby fluid is injected downhole to cut slots into the production casing or openhole reservoir formation, and thereby induce fractures in the reservoir formation. Conversely this technique may also be used in openhole and horizontal well ***stimulation*** procedures. This known ***stimulation*** procedure comprises pumping limited proppant concentration during fracturing through casing or in openhole formation, whereby fluid with proppant is typically pumped via tubing through Tungsten jet nozzles that are located at the distal end of the tubing. In the hydrajetting process, mixing of the tubing and annular flow-streams occurs adjacent to the reservoir formation as generally similar fluids are simultaneously pumped down casing. This procedure is typically limited to ***stimulation*** applications involving smaller fractures where proppant concentrations are relatively low (usually less than 5 pounds per gallon) in comparison to most typical sand-fracturing techniques, and furthermore the total amounts of proppant that are placed in the fracture are relatively low.

The hydrajetting process may include pumping of different fluids simultaneously down annulus and tubing, in terms of one fluid type consisting of proppant. This process is flexible in allowing different fluid types including acid to be used, but is also relatively expensive in comparison to typical known fracturing techniques. Annular rates are adjusted to maintain fracturing pressures as fractures are generated by the hydrajet fracturing process. A limitation in the use of this system occurs, however, as jets may become eroded during the fracturing injection process, in addition turbulent flow patterns may disperse proppant in the near-wellbore fractures. The proppant washout may be due to a Bernoulli affect, whereby the annular pressures are lower than the fracture tip pressures.

SUMMARY OF THE INVENTION

In accordance with the present invention, there is provided a real-time hydraulic fracturing process in which substantial quantities of both nitrogen and carbon dioxide may be separately injected, via the tubing string and casing annulus, to form, in the downhole region of the wellbore, a composite fracturing fluid that may include an aqueous-based fluid, a proppant, N2 and CO2 energizers and various other chemical components. This inventive process may be used to stimulate reservoirs in vertical and horizontal wells, and in openhole and cased wells. The inventive system may also be used for enhanced reservoir recovery procedures to remediate depleted reservoirs in mature fields, via short phase tertiary CO2 injection.

Downhole-blending proximal to the reservoir zone is accomplished by dual injection of different fluids through coiled or conventional tubing and casing annulus. A composite fracturing fluid is thus created downhole prior to injection into the reservoir formation fracture. The aqueous based fracturing fluid may be incorporated into either or both of the gases at the surface and may include proppant and other chemical components, which form the composite fracturing fluid upon mixing downhole. This ***downhole-mixed*** fracturing fluid is blended downhole to avoid excessive friction pressures and then injected at a desirable thickened viscosity and at a pressure sufficient to implement hydraulic fracturing of the selected reservoir interval.

Known additives, including thickening agents, may be incorporated into the base-fluid to increase fluid viscosity, to improve proppant suspension, leak-off and related rheological properties. Carbon dioxide may be provided in liquid phase via the tubing and nitrogen may be provided in gaseous phase via the casing, or conversely the carbon dioxide may be injected down the casing and nitrogen down the tubing. Thorough mixing of the propping agent with the composite ***stimulation*** fluid preferably occurs immediately above or adjacent to the reservoir interval where the induced reservoir fracture or fractures are propagated. The procedure of downhole-mixing may be accomplished concurrent with tracer monitoring, in real-time, as described in our U.S. Pat. No. 5,635,712 (Scott-Smith), which is hereby incorporated by reference.

In the event of a premature screenout, an operator typically immediately ceases pumping proppant down the casing annulus and the fracturing job is terminated prematurely, or conversely the operator might attempt to abruptly increase the rate of pumping in an often futile endeavor to create new fracture growth, or increase the existing fracture width.

However, these known techniques typically do not always yield satisfactory results, and may even worsen the problem in terms of screening out, fracturing out of the desired reservoir zone, or ruining the wellbore casing due to excessive pressures and resultant pipe rupture.

A variety of problems are avoided in real-time by this method of downhole mixing, which provides the ability to substantially instantaneously modify ***stimulation*** treatment by rapid changes in pump rate, fluid rheology and proppant concentrations. This inventive system typically minimizes friction pressures and thus provides lower treating pressures and higher pumping and injection rates. Downhole mixing facilitates true real-time modification of the fracture treatment, and provides near instantaneous alteration of fluid viscosity and proppant concentrations at the reservoir, as is described further below.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a schematic cross-sectional representation of a fracturing procedure showing the various stages involved.

FIG. 2 illustrates a typical downhole-blended real-time hydraulic fracturing operation illustrating surface facilities and pump trucks, with simultaneous injection of different components down tubing and casing to form a composite fracturing fluid in the downhole region.

FIGS. 3-5 illustrate variations and/or consecutive progression of ***downhole-mixed*** well ***stimulation*** procedures with pumping of various components down tubing and casing annulus.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

FIG. 1 illustrates various stages during a typical fracturing treatment sequence, whereby fracturing fluid is blended downhole and pumped in pre-pad (10), pad (20), proppant (30) and flush (40) stages. As indicated, aqueous fluid, which might also be comprised of gelled hydrocarbons, is pumped down casing (50) while the tubing 60) is a "dead string", which provides the operator measurement of bottomhole treating pressure during the fracturing process. Alternately, the surface-mixed composite fracturing fluid may be pumped down tubing (60), or the same fluid may be pumped simultaneously down both tubing and casing. The composite fracturing fluid is generally comprised of various additives, including gel, proppant, or energizers including CO2 and Nitrogen, which are mixed at the surface prior to pumping down the well for injection into the formation to induce fracturing.

In the inventive embodiment illustrated in FIG. 2, the novel process of employing carbon dioxide, nitrogen, aqueous fluid and other chemical additives in accordance with downhole mixing may be understood by reference to the hydraulic fracturing operation as indicated. Aqueous gel (65) with Nitrogen (70), and liquid CO2 (80) are pumped concurrently down casing (50) and tubing (60) respectively, at constant or variable ratios during successive treatment stages. The liquid CO_2 (80) is pumped from storage tank via high pressure line (110) by pump (120) through the wellhead (130) and down the tubing (60) during simultaneous pumping of gelled fluid (140) with methanol and Nitrogen (70) down the cased wellbore (50). Downhole-mixing forms a composite fracturing fluid (150) above or adjacent to perforations (160), which are located proximal to the desired reservoir (170) objective. A hydraulically induced fracture (180), shown in cross-sectional view, contains the composite fracturing fluid (150). Alternate arrangements of surface equipment, for mixing various components at the surface, are possible. The fluid content of the composite fracturing fluid is typically subject to water leakoff into reservoir formation (170). Different combinations of known fluid components and chemical additives may be mixed downhole to reduce the fluid leakoff.

FIGS. 3-5 show a ***downhole-mixed*** fracturing procedure sequentially as the treatment progresses through various stages. FIG. 3 shows the initial fracturing fluid (190) pumped via casing into the reservoir zone of the well adjacent to the reservoir formation to be fractured. Fracture initiation is established (as evidenced by formation breakdown pressure) whereupon the formation mechanically fails and one or more fractures (180) are formed during injection of this initial pad stage (190) into the reservoir formation. The initiation of a fracture or fractures in the formation usually is accompanied by a relatively abrupt and substantial decrease in bottomhole treating pressure, which is monitored by operator at the well site surface.

FIG. 4 shows the subsequent mixing downhole of composite fracturing fluid (150), as fluid component (200) is pumped via casing and CO_2 (80) is concurrently pumped down tubing. In this embodiment, the pump rates may be varied for the purpose of achieving desirable fracture growth and proppant placement within the reservoir zone. In addition, fluid rheology may be selectively altered, in real-time, as a result of modification of relative pump rates at surface of tubing versus casing. Both the composite fracturing fluid rheology and proppant concentration may be modified essentially at or near the perforations, in real-time. This system facilitates prompt changes in proppant concentration, which is particularly important under certain circumstances such as when attempting to avoid premature screenout of the fracturing treatment. Avoidance of premature screenout may be achieved by prompt reduction of proppant concentration in the downhole region by increasing the rate of clean (i.e. without proppant) fluid or energizer (CO_2, Nitrogen) relative to the proppant-laden aqueous fluid. Avoidance of screenout in real-time thus may be achieved by increasing the relative rate of clean fluid, or energizer, from tubing, with respect to sand-laden fluid that is pumped via casing. Both tubing and casing flowstreams may separately or together include chemical additives that are specifically applied to further minimize the rate of fluid leakoff into the formation, which contributes toward the occurrence of premature screenout.

FIG. 5 illustrates the pumping of a proppant-laden slurry (210) including energizers (such as N_2) down casing concurrent with the pumping of CO_2 (80) down tubing. Real-time modification of the composite fracturing fluid (150) and to another composite fracturing fluid (160), including varied proppant concentration, may be facilitated by adjusting the injection rates of tubing and casing relative to each other. The net composition of the composite fracturing fluid (i.e. rheologic properties) and proppant concentrations may be altered as desired by altering the rates that the tubing and casing components are pumped. For example, the composite fracturing fluid may be adjusted, in real-time, from a ratio of 40% CO_2-30% N_2-30% aqueous fluid slurry (with proppant) to a 80% CO_2-15% N_2-15% aqueous fluid slurry by increasing the volumetric rate of CO_2 pumped down tubing. Although the pumping equipment is located at the surface, like a syringe the effectuated increase in tubing pump rate is immediately evidenced at the bottom of the wellbore and results in a real-time change in the composite fracturing fluid entering the formation. As a result, the proppant concentration is changed in real-time by the increased ration of clean fluid or CO_2 relative to the proppant-laden slurry. The rate of change may be further accentuated by simultaneously decreasing the casing annular pump rate while increasing the tubing pump rate, such as might be indicated by premature screenout and the need to radically reduce proppant entry into the formation.

According to the present invention, each of at least two fluids used for fracturing formations penetrated by subterranean wellbores may be pumped down respective tubular conduits, simultaneously, to mix and interact in a downhole portion of the wellbore forming a composite fracturing fluid therein, which is then pumped into the formation/reservoir.

The pump rate of fluid in one or both tubular conduits may be selectively and individually varied to effect changes in composition of the composite fluid, substantially in real time to exert improved control over the fracturing process, including the quality, physical and chemical properties of the composite fluid entering the formation. Proppant transport qualities thereby may also be modified substantially in real time. Other benefits may also be realized, such as reduced friction losses, reduced hydraulic horsepower requirements, and improved pump rate limits over the restrictions that may be imposed by wellbore tubular sizes.

By providing separate conduits for respective separate fluid compositions at the surface, composite downhole fracturing fluid combinations that might otherwise have been impractical if mixed at the surface, may be permissible. For example, a first fracturing fluid phase including carbon dioxide may be pumped down the tubing, while a second fluid phase including nitrogen, gelled aqueous fluid and proppant may be pumped down the casing annulus. The first and second fluid phases may combine and mix downhole in the casing to form a composite fracturing fluid that might otherwise have exhibited too much friction loss to have been pumped from the surface as a composite fracturing fluid. In like fashion, cross-linking may be performed downhole in the casing without relying on "delayed" cross-linking techniques that result from predictable fluid pH changes. For example, a borate gel may be incorporated concurrently with CO_2, which if mixed at the surface the CO_2would act as an efficient breaker of the borate gel crosslinking action.

Often, a desirable embodiment may of downhole-mixing may be used to create viscous inter-fingering of CO_2or other gaseous phases within the aqueous pad fluid that is present in the formation fracture. Although mixing along the interfaces of the different density phases may also occur, the vertical separation of discrete phases in the fractures, due to fluid phase or density variations, may likely result. Under some circumstances this discrete separation of different phase types in the fracture is desirable, such as to avoid placement of proppant in water-productive zones, or to avoid fracturing into gas-oil, gas-water, or water-oil contacts in the reservoir.

The term "aqueous fracturing fluid" as used herein may be defined broadly to encompass any liquid fracturing fluid, including water based fluids, alcohol based fluids, or crude oil based fluids, or any combination thereof. Energizers such as carbon dioxide and/or nitrogen may be pumped down one or both tubular conduits, individually or in combination with one of the aqueous fracturing fluids or some portion thereof. "Carbon dioxide" may include liquid carbon dioxide, and may also include carbon dioxide miscibly dissolved in a liquid, or foamed with another liquid as either the continuous or discontinuous phase. "Nitrogen" may include also include nitrogen or a nitrogen containing compound alone, or mixed with, foamed, or partially dissolved in a liquid, or without a liquid. Carbon dioxide in the liquid phase is highly soluble in water, however, nitrogen is relatively insoluble in water, even at comparatively high pressures commonly encountered at the bottom of a well.

Water based fracturing fluids may include fresh water based fluids, sea water based fluids, or brine solutions, and may further include added salt compounds, such as KCl and NaCl. Alcohol based fracturing fluids may include aliphatic alcohols such as methanol, ethanol, isopropyl alcohol, tertiary butyl alcohol and/or other alcohol based compounds. Oil based fracturing fluids may also be included within the term "aqueous fracturing fluid" as used herein, and may include "live oil," "dead oil," "crude oil," "refined oil," condensate, or other hydrocarbon based fluids. Any combination of gelling, thickening, cross-linking, or other known fracturing fluid additives may be included in any of the above fracturing fluids.

Another embodiment comprises pumping aqueous fluid with proppant and other chemicals additives, including methanol or other alcohols, down casing while concurrently pumping CO_2 down tubing. Or conversely CO_2 may be mixed with Nitrogen, or 100% Nitrogen may be pumped down tubing for admixture with fluid components. As a result of pumping this configured embodiment, the composite fracturing fluid that is comprised of aqueous fluid, methanol, proppant and CO_2, is pumped at substantially reduced pumping pressures relative to the current industry practice of first mixing said components in surface tanks prior to pumping down the wellbore. The advantages of this downhole-blended embodiment include lower treating pressures, lower horsepower pumping requirements, and lower overall costs related to the procedure. In addition, this procedure provides means for adjusting both fluid rheology and proppant concentration in real-time. Said adjustments in rheology include changes in gel strength, viscosity, and gel-breaker quality.

In another inventive embodiment, downhole-mixing may be achieved by the pumping of aqueous gel crosslinking agents down tubing or casing, while concurrently pumping gel crosslinking activators and other chemical additives down casing or tubing, respectively, to result in a more precisely controlled crosslinking of the composite gelled fracturing fluid. Cross-linking agents may be blended in the downhole region with polymeric thickening agents comprising borate gels or multivalent metal ions such as titanium, zirconium, chromium, antinomy, iron, and aluminum. The cross-linking agents and polymer combinations include, but are not limited to mixing guar and its derivatives as a polymer with a cross-linking agent of titanium, zirconium or borate; a polymer composition of cellulose and its derivatives cross-linked with titanium or zirconium; acrylamide methyl propane sulfonic acid copolymer cross-linked with zirconium.

Downhole mixing provides efficient turbulent dispersion of both carbon dioxide and nitrogen in the gelled aqueous fluid. This downhole-blending procedure may also be conducted with either or both Nitrogen and CO2 added into the ***downhole-mixed*** composite fracturing fluid, in various stages or the entirety of the fracturing treatment. Or conversely, Nitrogen and CO2 energizers may not be required in some circumstances, such as when adequate reservoir pressures are present to assure a relatively prompt flowback and cleanup of the composite fracturing fluid. C0.sub.2 may be supplied as a liquid at about -10.degree. F. to 10.degree. F. and at a pressure of about 250 to 350 psig. Nitrogen may be supplied as a gas, normally at ambient temperature of from about 65.degree. F. to 115.degree. F. The composite fracturing fluid may be at a pressure at the wellhead that is typically within the range of from less than 1,000 to more than 12,000 psig.

In addition, various chemical additives may be mixed downhole to modify gel quality. ***Downhole-mixed*** hydrophyllic gels may be be employed, which swell when water molecules are encountered. As a result, gels may be primed by downhole-mixing with activators and known chemicals to create freshly reactive hydrophilic gels that drastically increase fluid viscosity whenever water-productive zones are encountered, thus plugging or sealing fractures as a result. Thus, as fracture propagation out of a desired reservoir interval occurs, hydrophilic molecules may be created in the downhole region for binding water molecules and concurrently sealing the fracture to minimize unwanted water production.

Enhanced gels may be created by downhole blending. Chemical mixtures that are created or activated by downhole-mixing may be employed to modify relative fluid or gas flow characteristics of the reservoir rock. Relative reservoir permeability may be modified by application of known chemicals and known activators that are mixed in the downhole region, particularly those that react relatively rapidly, as compared to current practices of pumping surface-admixed gels that often may be compositionally unstable. CO2and nitrogen may be included in this process. CO2, nitrogen and various other known additives including surfactants may be mixed downhole to alter wetting properties and interfacial tension angles between the hydrocarbon and reservoir rock. The gel rheology and ratios of nitrogen and carbon dioxide to the aqueous fracturing fluid may be altered at various stages of operation, in real-time, if a sudden unanticipated change in bottomhole treating pressure occurs, or as early premature screenout is evidenced or suspected.

During the fracturing process, a typical propping agent, such as Ottawa frac sand or ceramic particles, may be employed in concentrations ranging from less than 0.5 to 15 pounds of sand per gallon of fracturing fluid. Viscosifying agents may be employed to increase the viscosity of the aqueous solution and to increase the propping agent concentration, which may be progressively increased, or decreased as desired during the fracturing treatment.

Subsequent to the injection of the propping agent into the fracture, it may be desirable to complete the operation with the injection of a wellbore flushing fluid that is absent propping agent. This flushing fluid functions to displace previously injected propping agent into the fracture and reduces the accumulation of undesirable quantities of propping agent within the well proper. The flush stage may also include various chemical additives including resin activators and inhibitors.

At the conclusion of the displacement of proppant-containing fluid, the fracturing operation normally is concluded by the injection of a flushing fluid to displace the propping agent into the fracture. The well may then be shut in for a period of time to allow the injected fluid to reach or approach a state of equilibrium, with both the carbon dioxide and the nitrogen in the gaseous phase. After the well is placed on production by flowing the well back, via a positive pressure gradient extending from the reservoir to the surface via the wellbore, the co-mingled nitrogen and carbon dioxide function to effectively displace the aqueous fracturing fluid from the formation. This provides a clean-up process at the conclusion of the fracturing operation since both nitrogen and carbon dioxide dispel fluids from the formation.

By using the inventive process of downhole mixing, the operator has more options when faced with premature screenout. These options include simultaneously increasing pump rate down the tubing with circulation of the casing fluid into pits, or conversely, the operator may elect to dilute proppant concentration entering the reservoir in real-time by increasing the pump rate of clean fluid relative to the pump rate of proppant-containing slurry, thus decreasing the amount of proppant per volume of composite fracturing fluid entering the formation. This inventive downhole mixing method may also be used to avoid screenout by increasing the effective admixture of additives for the purpose of minimizing fluid loss to the formation, in real-time.

As apractical matter, the addition of polymeric thickening agents, and other additives incorporated therewith, hydration of the aqueous fluid to form the initial gel, and the addition of propping agent may be accomplished under ambient surface temperature and pressure conditions. Injection of these components via tubing and casing is accomplished to induce downhole-mixing adjacent to the reservoir.

A cross-linking agent may be injected separately (down tubing) from the other chemical components (down casing), so that initiation of cross-linking reaction occurs downhole immediately prior to injection of the composite fluid into the reservoir. This facilitates avoidance of a premature increase in viscosity of the fracturing fluid as it travels downhole in the casing or tubing, which often occurs with surface-mixed composite fluids. Premature viscosification of the fracturing fluid creates excessive treating pressures as a result of friction loss. During a fracturing procedure, increased fluid friction requires increasing hydraulic horsepower, which increases costs and often restricts overall pump injection rates.

The composition of the aqueous phase of the fracturing fluid may include polymer gelling agents, surfactants, clay stabilizers, foaming agents, and potassium salt. Methanol may be added to the fracturing fluid in those cases where the formation contains substantial quantities of clay minerals. It is often times desirable to add from about 10-20 volume percent methanol to the fracturing fluid in such circumstances. Polymeric thickening agents are useful in the formation of a stable fracturing fluid. Examples of known thickening gelling agents may contain one or more of the following functional groups: hydroxyl, carboxyl, sulfate, sulfonate, amino or amide. Polysaccharides and polysaccharide derivatives may be used, including guar gum, derivatized guar, cellulose and its derivatives, xanthan gum and starch. In addition, the gelling agents may also be synthetic polymers, copolymers and terpolymers. Cross-linking agents may be combined with the solution of polymeric thickening agents including multivalent metal ions such as titanium, zirconium, chromium, antinomy, iron, and aluminum. The cross-linking agents and polymers may be combined as desired via downhole mixing. These combinations include but are not limited to (1) admixing guar and its derivatives as a polymer with a cross-linking agent of titanium, zirconium or borate; (2) polymer composition of cellulose and its derivatives cross-linked with titanium or zirconium; (3) acrylamide methyl propane sulfonic acid copolymer cross-linked with zirconium. The amount of thickening agent utilized depends upon the desired viscosity of the aqueous phase and the amount of aqueous phase mixed downhole in relation to the energized phase, that is, the liquid carbon dioxide and nitrogen phase. As the amount of liquid carbon dioxide and nitrogen increases, the amount of aqueous phase will commonly be 20% to 50%. Reservoir injection rates and composition of the component fracturing fluid will vary in the downhole region as a function of modification of relative pump rates for tubing and casing. This allows the operator to control proppant concentration and relative gas-fluid ratios as the composite fluid enters the reservoir fracture, all of which may be varied or kept constant, in real-time as desired by the operator.

Additives and water are typically admixed into an aqueous fracturing fluid at the surface throughout the fracturing operation, or the gelled fluid may be formulated before the operation and kept in surface storage tanks until needed. Various additives as described may then be blended into the water in the tanks, or via downhole blending, depending on the operator's objective intent. After additives are thoroughly blended with the water, the water becomes "gelled", whereby the thickened aqueous fluid may be transferred from the storage tanks to a blender. Proppant, when required, may be added via mixing tub attached to the blender at a selected rate to achieve the required concentration, in pounds per gallon of liquid, to obtain the desired downhole concentration. The treating fluid or gel-proppant slurry may be transferred by transfer pumps at a low pressure, usually about 100-300 psi, to high pressure generally greater than 500 psi, by tri-plex pumps. The tri-plex pumps inject the separate fracturing components into the treating lines that are connected directly at the wellhead to tubing and casing, at a desired rate and pressure adequate to hydraulically fracture the formation.

Carbon dioxide may preferably be introduced in the liquid phase down the bore of the tubing string, whereas typically nitrogen is pumped in the gaseous phase down the casing (annular area between the tubing string and the casing). The agitation and turbulent shearing associated with downhole blending provides adequate mixing of the carbon dioxide and nitrogen within the aqueous fluid mixture. Downhole mixing according to this invention also provides uniform blending of carbon dioxide and nitrogen with the aqueous phase and forms a composite fracturing fluid with desirable proppant-carrying properties.

The aqueous base fluid phase may contain various chemical additives routinely used by those skilled in the art, including gelled hydrocarbons, and may be pumped separate for mixing downhole. For example, polymers, cross-linking agents, catalysts, and surfactants, and the aqueous phase may also contain one or more biocides, surface tension reducing non-emulsifying surfactants, clay control agents, salts, fluid loss additives, buffers, gel breakers, iron control agents, paraffin inhibitors and alcohols. Various of these components may be injected separately via tubing and casing for admixture in the downhole region of the well.

Having described specific embodiments of the present invention, it will be understood that other modifications thereof may now be apparent to those skilled in the art. The invention is thus intended to cover all such modifications of downhole blended fracturing, which are within the scope of the appended claims.

* * * * *

Sonication Stimulation of Stripper Well Production in East Gilbertown Field, West-Central Alabama

FINAL REPORT

For the period
July 1, 2003 to September 30, 2004

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ABSTRACT

This study evaluated the potential of sonication or acoustic energy to increase oil production in a stripper well located in the East Gilbertown Field, West-Central Alabama. Two field tests were performed; in each test production was increased by a minimum of 15% to as much as 30% for an initial period following sonication. Production levels gradually returned to pre-testing levels in a few weeks. All of the project's objectives were met. In addition, two first-time accomplishments were realized: 1) the system was operated downhole continuously for more than 40 hours, and 2) a method was devised that allowed simultaneous sonication and pumping of the produced fluid. Operating data on optimal frequency levels and power intensities were collected. Preliminary economics indicate a payback of the sonication system in 10-30 months depending on the additional amount of oil produced (0.32-0.48 m^3) (2-3 barrels/day) and the price of oil at the time of production. Recommendations are made for a series of long-term tests comparing and contrasting continuous and intermittent acoustic stimulation, evaluating chemical additives to aid in viscosity reduction, and determining the lateral extent of acoustic stimulation. Recommendations are also made for the development of the next generation of actuators and sensors.

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INTRODUCTION

Currently, world oil demand almost equals world oil supply; within the next few years demand will exceed supply. World oil production is almost 12,789,600 million m^3 (80 million barrels) a day; in 25 years the world will need 19,984,125 million m^3/day (125 million barrels/day). At the present, oil demand in the U.S. consumes 25% of the world's oil production. Demand in China recently has seen a phenomenal growth – 33% in 2003, 20% more in 2004. China now consumes about 9% of the world production. Many of the oil-producing nations are in politically unstable situations. The geopolitical pressures on oil are only going to get worse. In the short term, expanded and enhanced technology use in oil and gas exploration and production, plus the role of conservation, will provide some relief. In the medium-to-long-term, alternative sources of energy will be needed.

In the United States the situation is challenging. The U.S. has long been an importer of oil. We use about 3,357,333 m^3 of oil per day (21 million barrels of oil per day), but produce only about 1/3 of our needs. In 1970, U.S. production peaked at 1,598,730 m^3/day (10 million barrels/day); since then there has been a gradual fall-off in production. In 2002, production averaged 927,263 m^3 of oil per day (5.8million barrels of oil per day). Many reasons exist for the fall-off in production; the two most commonly cited reasons are market conditions and reserve depletions. Many wells and well fields have been shut-in. In the case of heavy oil deposits, the cost of generating steam to produce the oil has risen substantially. Environmental issues associated with developing new oil prospects are also mentioned as increasing the cost to produce oil.

Many of the oil fields in the U.S. are in declining primary (initial) recovery (as opposed to secondary or aided recovery), yet still have the capacity for further development. This project was conducted in such an area, the East Gilbertown Field in West-Central Alabama.

East Gilbertown Field, established in 1944, is the oldest oil field in Alabama. Production is from the Cretaceous Eutaw Formation sandstones and the Selma Group fractured chalk. From a peak production level in the early 1950's, oil production has declined to borderline profitability today, following a brief recovery period in the late 1970's. Today the focus of production efforts is on the Eutaw Formation. Eutaw wells normally produce for 20-25 years (average), peaking within the first two years of production at an average of 2,734 m^3/year (17,100 barrels/year). Average cumulative production from Eutaw Formation wells approximates 25,580 m^3 (160,000 barrels) or between 2.4-3.0 m^3/day (15-19 barrels of oil/day) of heavy (API 18°) oil.

East Gilbertown Field is typical of many fields throughout the United States that are in declining primary recovery and remain underdeveloped. Many of the wells in these fields are “marginal” wells. Marginal oil wells produce no more than 2.4 m^3/day (15 barrels of oil per day) or produce heavy oil, i.e., oil with an API index of less than 20. The average marginal oil well produces approximately 0.35 m^3/day (2.2 barrels of oil/day), but they comprise 84% of domestic oil wells (over 400,000) and produce more than 20% of our domestic oil – an amount equal to imports from Saudi Arabia (Fuller, 2004). Limited profitability and produced-water environmental issues have prevented many companies from attempting to increase production. Recompletion, in-field drilling and borehole extension are all possible conventional techniques to increase production. Secondary recovery via water flooding is not viable for the Eutaw Formation.

As stated in a December 1998 U.S. Department of Energy report (Pashin et al., 1998), "it is imperative that recovery efficiency be optimized and that unconventional opportunities be pursued to avoid premature abandonment of existing fields".

In order to avoid premature abandonment of these fields (and their remaining resources), the oil and gas industry needs to look at innovative, unconventional technologies for stimulating production. One of these technologies is sonication, i.e., acoustic energy. This project was designed to evaluate the potential for using sonication as a stimulation tool for increasing production from stripper wells.

The objectives of the project were:

1. To evaluate the use of sonication to stimulate oil production in stripper wells;
2. To develop "learning curve" data and know-how on methods and techniques of employing a sonication system downhole in an active well; and
3. To collect first-cut data on the economics of the process.

EXPERIMENTAL

In this section the science of sonication is discussed, the sonication device and auxiliary equipment are described, the field setup is explained, and the experimental protocol is presented.

The Science of Sonication

The science of sonication has been studied for more than 200 years. Early experimentalists used tuning forks (frequency) to show how acoustic/sound energy could cause ripples on the surface of water, and they also noted the extreme agitation caused when a tuning fork came in contact with the water. By the 1840's, materials had been discovered or developed which allowed the conversion of electrical and electromagnetic energy into mechanical energy. In 1842, James Joule discovered that an applied magnetic field (coil) could change the length of a bar of iron by "constricting" it. This magnetostrictive effect, named the Joule effect, is measurable and can be repeated virtually without fatigue in the metal. The physical dimension changes in such a bar of magnetostrictive material can be transformed into sound energy. Magnetostriction became the basis for numerous acoustical devices, including naval sonar. The materials favored in magnetostrictive devices, mainly nickel, became somewhat scarce during the period of the First World War due to demand for nickel for use in gun barrels and barrel liners. There was substantial incentive to develop other materials for transduction and these efforts led to investigations into piezoelectric (pressure-electric) materials and effects.

In a piezoelectric material, the application of a force or stress results in the development of an electrical charge in the material. Conversely, the application of a charge to the same material will result in a change in physical dimensions (strain) of the object. This movement can be converted from mechanical to sound energy. The development of piezoelectric ceramic sonar and the use of nickel as an energy converting material (transducer) reached their peak during World War II and for the ensuing 30 years, but eventually the physical limits of these materials were reached.

In the early 1970's, scientists at the Naval Ordnance Laboratories (now the Naval Surface Warfare Center) began experimenting with using the rare earth metals in magnetostrictive devices. Certain metal alloys of the lanthanide series showed tremendous potential for extremely high levels of magnetostriction. When a magnetostrictive rod is activated by an alternating current produced magnetic field, the oscillations (250-400 times a second) create an intense acoustic energy pressure wave that can be transmitted through a material.

Following the declassification of various sonication technology materials and data by the military in the early 1990's, considerable scientific and engineering innovations have been made in the application of acoustic energy to systems in order to affect physical and/or chemical changes in system components. Equipment and materials have evolved to the point that much larger amounts of energy can be generated for sonication purposes permitting larger and more efficient applications for a variety of different uses.

The power available in today's generation of magnetostrictive sonication materials and equipment – 1,000-6,000 watts – dwarfs what was being used in the laboratory only a few years ago, i.e., units with 350-500 watts of power. The tremendous increase in power, plus the much smaller size of sonication equipment, allows users to apply sonication technology to a number of situations at power levels previously unavailable. Thus, the technology can be used in new applications in various industrial sectors.

The physics of sound and sonication are fairly well known. Sound is a mechanical wave that consists of a pressure disturbance transmitted by means of molecular collisions in a fluid (gas or liquid). The term sonication refers to the application of sound waves (acoustic energy) transmitted through a liquid medium (water, oil, etc.) as a wave of alternating cycles of increasing and decreasing pressure. An analogy to visualize the movement of sound through a fluid is that of a stone tossed into a pond or pool of quiet, standing water. Waves radiate outward in all directions from the point where the stone hit the water (Figure 1). These are surface waves consisting of two parts – a peak or elevated portion and a trough or depressed portion. If a cork or other floating object were in the water as a wave passed, it would move up and down (perpendicular to the direction of wave motion) as each peak and trough passes its location. These types of waves are termed transverse waves where the particles of the transmitting medium move perpendicular to the wave direction; light waves are transmitted in this form.

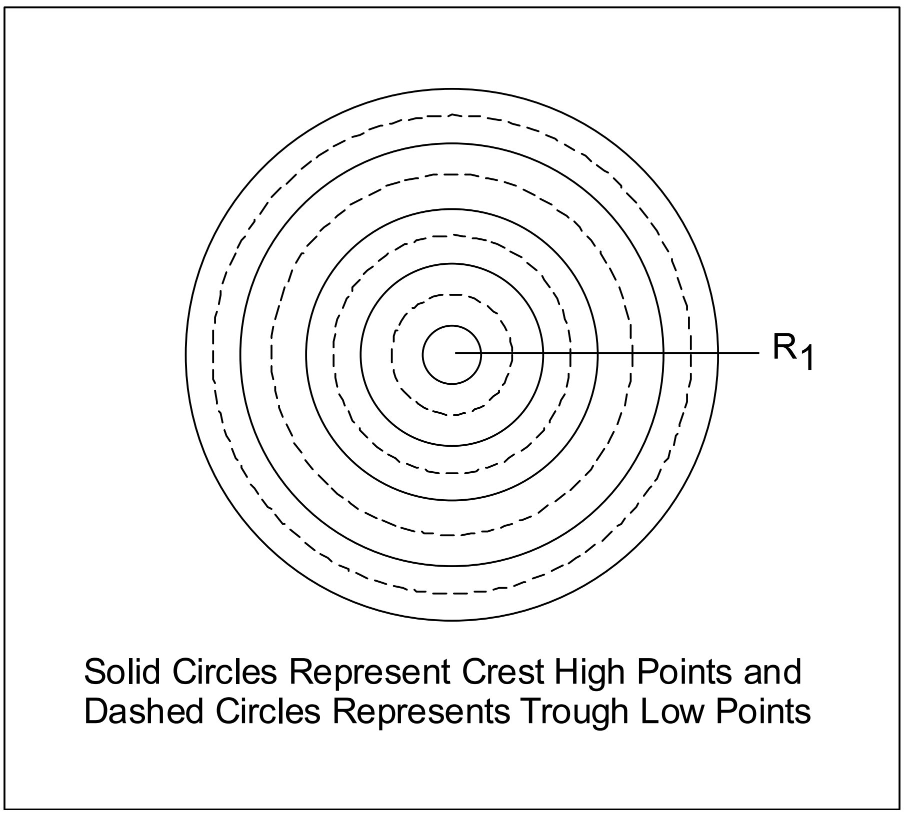

Figure 1 Illustration of Surface Waves on Water

Figure 1 is drawn from a perspective of being above the liquid surface looking down at the waves. If a cross-section of this system were observed along any radius from the center outward (for example R_1 in the above drawing), it would look like the drawing in Figure 2. This illustration shows a cross-section of a single wave with the wavelength and amplitude labeled. Here the water surface is shown as a plane where the pressure is atmospheric (P_a).

Beneath the liquid surface, within the liquid itself, sound waves take on a longitudinal (compressional) form meaning that the particle motion is in the direction of wave propagation. Compression cycles exert a positive pressure on the liquid, pushing molecules closer together, while expansion cycles exert a negative pressure, pulling molecules away (rarefaction) from each other. These conditions are represented by the spacing of the vertical lines and the horizontal arrows in Figure 2. The molecules tend to be pulled apart (pressure decreases) as the trough of a wave passes and pushed closer together or compressed (pressure increases) as a wave crest passes. Thus, within the fluid, the passage of a single wave of sound energy represents an alternating decrease and increase in pressure, which can be visualized to be like the sine wave representation of a surface wave shown here. The unit of measure of sound frequency is the Hertz (Hz), which is one cycle of compression and expansion or rarefaction (passage of one wavelength) in one second; a kilohertz (kHz) is one thousand cycles per second and a megahertz (MHz) is one million cycles per second. Where sound energy falls within the spectrum ranging from below the threshold for human hearing (16 Hz) to the upper level (18 kHz) is determined by the sound frequency. Ultrasound is defined as that sound above the threshold of hearing with frequencies between 20 kHz and up to 500 MHz. Sonochemistry, a rapidly growing area of research and technology development, refers to the discipline and phenomena of affecting chemical reactions by the application of sound waves (see Mason, 1999; Mason and Lorimer, 2002). Figure 3 illustrates the sonic spectrum and some applications of sound energy of various frequencies.

When the amount of energy added to the system is increased, the amplitude of the sound waves will increase as the frequency (wavelength) is held constant. As this occurs, localized pressure in the sonicated liquid may drop below its vapor pressure during the rarefaction portion of individual sound waves (Figure 4). This will initiate the formation of microbubbles in the rarefaction zone when the liquid is locally vaporized and a bubble forms around the vapor pocket. These bubbles initially are very small, on the order of 1 µm (1×10^{-6}m, 0.001mm). This phenomenon of bubble formation is called cavitation and is the basis for most of the physical and/or chemical changes that occur in the liquid medium during the sonication process. In addition to the vaporization process due to pressure drops, the rarefaction or extension phase of the cycle causes molecules of the liquid medium to pull apart when the negative pressures exceed the tensile strength of the material or the distance between the molecules exceeds the critical molecular distance necessary to hold the liquid intact. This forms cavities or voids in the liquid medium, which produces additional bubbles during cavitation. During the alternating cycles of pressure increase and decrease, the microbubbles fluctuate in size, growing in rarefaction phases and shrinking in compression phases. Eventually, some of the individual bubbles grow to a critical size and then implode violently (collapse to zero size), releasing a large amount of localized energy (Figure 5).

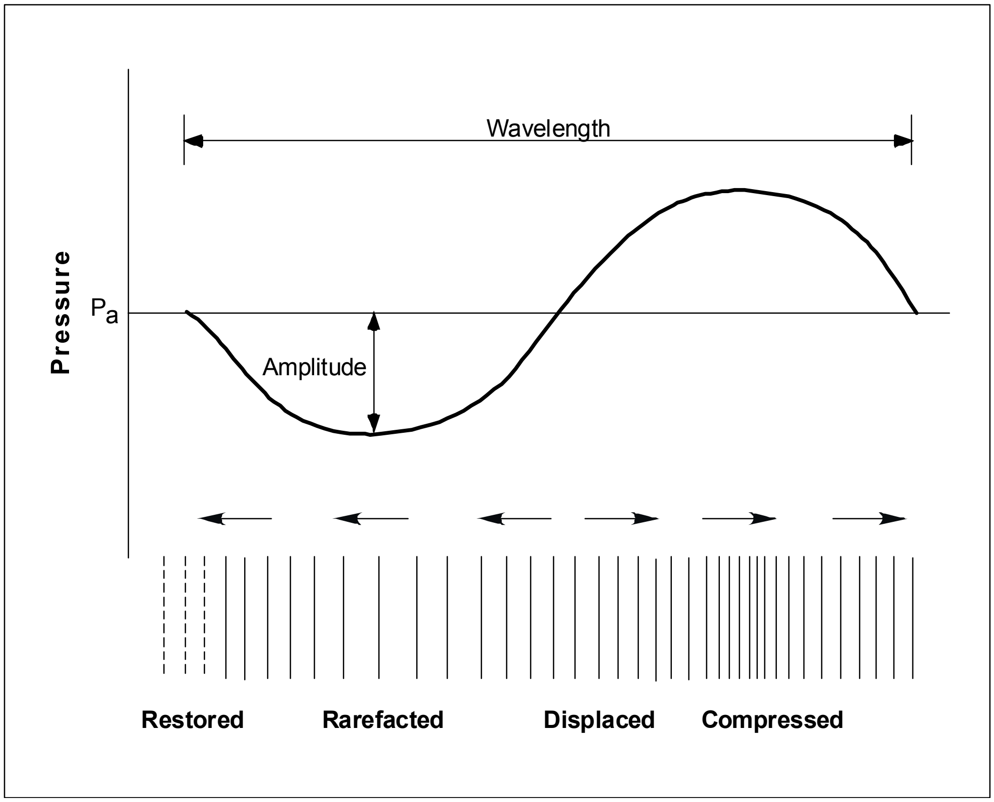

Figure 2 Illustrations of a Single Sound Wave and the Alternating Increase and Decrease in Pressure

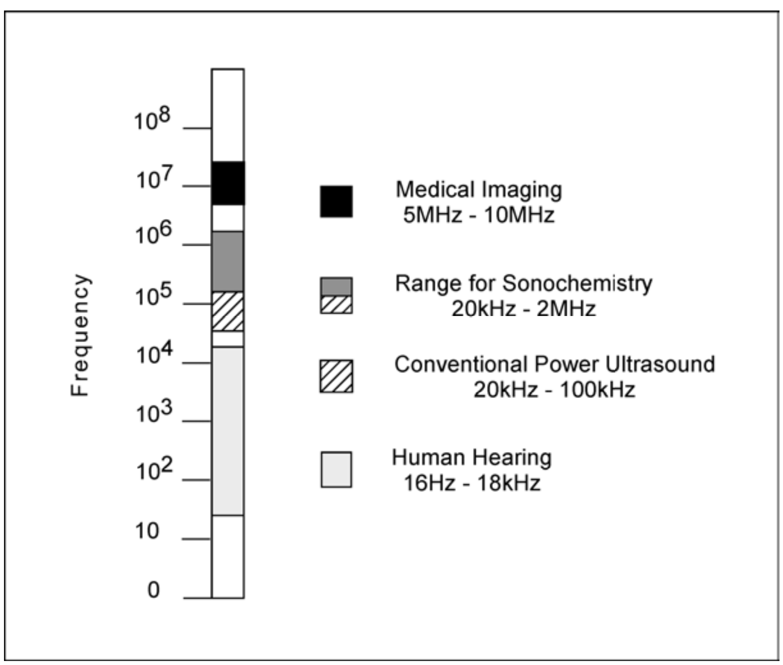

Figure 3 Sound Frequencies

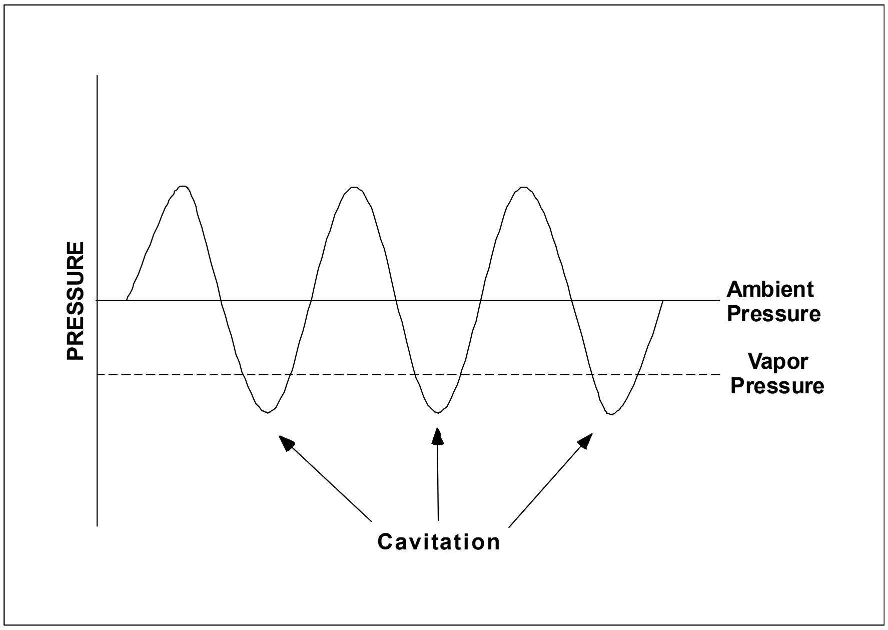

Figure 4 Illustration of Pressure Drop Below Vapor Pressure of a Liquid Causing Cavitation

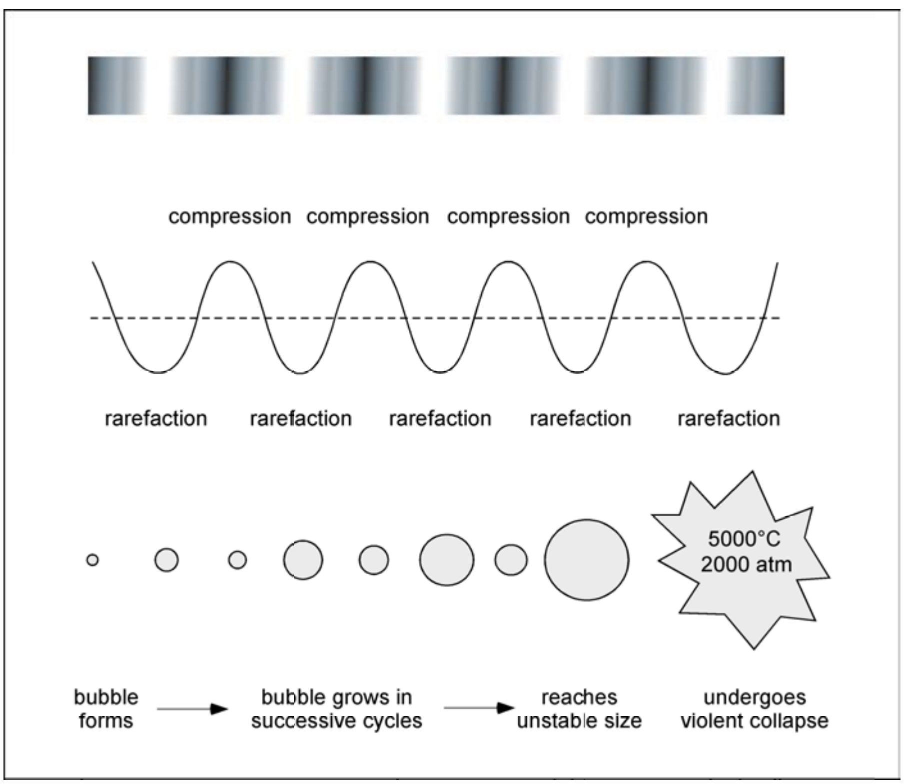

Figure 5 Schematic Illustration of Bubble Growth and Collapse during Cavitation

Energy released when cavitation bubbles collapse occurs in three forms. Temperatures on the order of 5,000 ^{o}K (8,500 ^{o}F) and pressures in excess of 1,000 atmospheres have been calculated to occur at the collapsing bubble interface during implosions (see Suslick, 1994). Furthermore, under some circumstances, light emissions also have been observed during sonication (sonoluminescence), which further indicates the release of intense energy from the cavitation process (Crum, Mason, Reisse, and Suslick, 1997; Beckett and Hua, 2001). It is also possible to generate strong, but small-scale shock waves within the sonicated fluid resulting from the sudden input/pulse of increased pressure when a bubble collapses. It must be remembered that all of these cavitation-related phenomena are on a very small scale and the energy dissipates very quickly in the immediate vicinity of the bubble. Consequently, the overall physical properties (e.g. temperature) of the ambient fluid tend to remain relatively unchanged. However, the very large amount of energy involved does have the capacity to produced dramatic, localized changes in the chemistry and physics of the sonicated medium (Mason and Lorimer, 2002; Mason and Peters, 2002).

In water, the reactions within and adjacent to a collapsing bubble result in the formation of hydroxyl (•OH) and hydrogen (H•) radicals. Although these chemical species are extremely short-lived, they are very reactive and effective in destroying organic compounds contained within the water. The intensity of cavity implosion and the nature of the reactions involved can be controlled by process parameters such as the sonic frequency, sonic intensity (power per unit volume of liquid), static pressure, temperature, and the addition of reactive oxidants such as hydrogen peroxide (H_2O_2), ozone (O_3), and metal catalysts. Cavitation reactions supplemented by these additives produce an advanced oxidation system that has many potential environmental and industrial applications.

The Sonication Device

The sonication system consists of 1) an actuator or transducer, a device for converting electrical energy to mechanical energy; 2) a horn, a device for directing the mechanical energy into horizontally transmitted acoustic energy waves; and 3) an AC power source with a manual oscillator module.

The actuator used in this project was a modified version of an AA090J series model manufactured by ETREMA Products Inc. of Ames, Iowa. Information on the actuator is available on the ETREMA website, www.etrema-usa.com.

The horns were cut from 2" titanium bar stock according to a design pattern developed by Furness-Newburge, Inc. For this project, the space between the disks was approximately 2.5 cm (one inch). Related work had determined that this spacing works well when oil is the fluid medium for sonication. The upper end of the horn is threaded and connects with the base of the actuator.

The system's power is controlled by a Titan Series MAC-O1S mainframe AC power source manufactured by Compact Power Co. of Yorba Linda, California. The sonication system for this project was powered by two mainframe units, each capable of producing 1,000 watts of output power, that were connected in series to increase the voltage and available power. A Titan MOS-01 manual oscillator module with digital readout capability is connected to the mainframes. More information on and specifications for Titan series products are available at www.CompactPowerCo.com.

Field Setup

Two field tests were completed during this project. For each test, a field service company was put under contract to provide a wire-line truck and power. The wire-line truck contained a motorized cable reel that allowed the operator to determine the downhole depth to which the sonication device was lowered. A generator provided power. The power was sent to the Titan power source controls mounted on an equipment rack in the cab of the wire-line truck, and then connected by wires from the controls to leads in the wire-line cable. The cable was linked to the sonication system by a connector (Baker-Atlas AS4-0100) that transmitted the electrical current from the cable to the sonication system. A rigging crew was brought on site to handle the removal and reinsertion of pipe and tubing when necessary. For the first test, the rigging crew brought a backhoe for digging a pit to collect the produced oil. The pit was lined with rubber and a vacuum truck periodically emptied the pit of oil. For the second test, the oil was pumped directly to the oil storage tank for measurement and water separation. The well selected for the tests was the Rex Alman #3, located in the SE 1/4 of the NE 1/4 of Section 4 in Township 10 North, Range 3 West in the East Gilbertown Field, Choctau County, Alabama. The depth to the oil pay zone was 958 m (3143 ft) below grade; the pay zone was 3 m (10 ft) thick.

Experimental Protocol

Originally, this project had scheduled three downhole field tests. The costs associated with the field service companies providing support for the first downhole test exceeded the amount budgeted. As a result, the project team requested, and was given, permission to modify the project scope into two downhole field tests, while still meeting all of the planned objectives for the three scheduled tests. The experimental protocols are presented for production data and for process parameter date.

Production Data

The primary overall objective of the project was to evaluate the use of acoustic energy to stimulate oil production from a stripper well. For the first test, conducted from October 13 through October 17, 2003, data were collected from two different approaches. First, daily production data were obtained from records collected by Field Management LLC and subsequently sent to the Alabama Oil and Gas Board, for the month preceding the field test of October 14-17, 2003 and the month following the test. In some cases the daily production totals were unavailable, because the production data from the test well had been combined with another well or wells.

Second, during the test, oil was collected in a container of known volume by inserting the container into the produced oil stream and collecting all of the oil flowing from the open casing until the container was full, while measuring the time to fill the container with a stopwatch.

These measurements were made periodically with no set schedule and not for statistical purposes, but to obtain data on flow rates in relation to changing frequency levels and power intensities. This method was used out of necessity because, for this test, the well was open and the oil was not being pumped or collected. No flow meter was available, thus no reliable method other than the one used was available.

For the second test, the measurement method had to be changed. Because the sonication system was placed downhole and the tubing reinstalled before the test began, all oil produced was collected and transported by an underground pipe to the oil water separator/oil storage area. Therefore, the container/time method could not be used. The project team was interested in knowing daily production rates for the test well. Since the beginning of 2004, production from the test well had been combined with production from two other wells and sent to the separator/storage area. Field Management, LLC, operator of the well field, agreed to isolate the production from the test well for 30 days before the scheduled field test and to maintain the isolation for 30 days following the test, allowing a more realistic evaluation of the effect of sonication on production.

Process Parameter Data

Another objective of this project was to develop data and know-how on methods and techniques of using a sonication system downhole. The goals of the field tests were to identify the optimum frequency level, power intensity, and output current during the first test, then to use this information in conducting the second test where the variable was time, i.e., to run a continuous downhole test for at least 40 hours.

This project was conducted in parallel with a major study funded by the U.S. Department of Energy's Small Business Innovative Research (SBIR) program. This study – SBIR Phase I and Phase II, titled "Acoustic Energy: An Innovative Technology for Stimulating Oil Wells" – is evaluating sonication technology as a means of lowering the viscosity of oil. This detailed laboratory testing study was conducted using a specially designed and fabricated multi-actuator reactor. The laboratory portion of the project was done with the assistance of the University of Alabama at Birmingham's Department of Civil and Environmental Engineering. The project involves the evaluation of sonication's impact on three oils: a light crude with an average API index of 35, a heavy crude with an API index of 18 and a very heavy crude with an API index of 8. The 18° heavy crude is from the formation in the East Gilbertown Field being tested in the Stripper Well Consortium (SWC) project.

The SBIR study is evaluating acoustic frequency levels, various horn configurations, chemical additives, and power intensities on the viscosity of the oils. Thus a great deal of information relative to the testing in the SWC project was known from preliminary results of this other project. For example, for the SWC project, frequency levels were placed into four categories based on information developed in the SBIR study: 1) Low: 950-1150 Hertz; 2) Intermediate: 1150-1350 Hertz; 3) Medium: 1350-1550 Hertz; and 4) Medium Plus: 1550-1750 Hertz. Varying the spacing between disks on the horn (see Photo 1 in Appendix C) was evaluated in terms of viscosity reduction, and the optimum power intensity range was narrowly defined. This information was used as input to the SWC project. In the SBIR study, sonication without the addition of chemicals reduced viscosity by 15-42% in the laboratory reactor. Chemicals used in the SBIR study reduced oil viscosity by 13-40%. Combining the two – chemicals and sonication – reduced the viscosity of the heaviest oil (API index of 8) by 80%. Chemicals were not used in the SWC study.

The primary methods for determining optimum frequency are listening to the sound of an actuator under load (a trained ear can recognize the harmonic sound), watching the formation and activity of cavitation bubbles, and observing oscilloscope patterns. Because the activity for this project was taking place more than 914 m (3000 ft) below the ground surface, oscilloscope patterns were used to identify optimum patterns with the realization that harmonics at various frequency levels could produce very similar patterns. Power intensities and the output current were controlled and monitored through the MAC-O1S power supply.

The first test was designed to identify an "optimum" frequency through oscilloscope pattern recognition, observe the impact on production, then modify the power intensity and output current while maintaining an "optimum" pattern and note any changes in production. After the first test was completed, the test plan had a six-week interval built into the schedule to allow for monitoring of production data and for evaluating and determining the optimized parameters for the next test. Once optimum conditions were identified, they were used as input parameters in test two, where conditions were run continuously, as opposed to the 7-8 hour runs of test one.

RESULTS AND DISCUSSION

Results

Field Test 1, October 13-17, 2003

Upon receipt of the actuators and power supplies and following fabrication of the horns, the system was assembled and tested in the Furness-Newburge, Inc. facility in Versailles, Kentucky. After completing several tests using water (initially) and then oil, the sonication system, consisting of the actuators, the power supplies, and the horns, was and shipped (via ground transportation) to the field test site in Alabama.

October 13. The project team tested the sonication system onsite for mechanical and electrical reliability prior to its being inserted downhole. A centering device and a sinker bar were attached to protect the actuator and horns each time they were sent downhole. The pump and tubing were pulled from the hole, and the hole was left open for insertion of the actuator.

October 14. The field service crew ran a Gamma Neutron Ray Log to identify the depth to the top of the pay zone (958 m, 3143 ft below grade) and the thickness of the zone (3 m, 10 ft). The project team had decided to use the intermediate frequency level category (1150-1350 Hertz), based on the SBIR study data, with an average power intensity of 67%, i.e., output power of 1340 watts (2000 watts x 67%) and an average output voltage of 548 volts rms (root-mean-square). The 3-m (10-ft) pay zone section was traversed by lowering the actuator 15 cm (6 in) every 40 minutes. The test was run for seven hours.

According to the well operator, the well had been producing approximately 0.95 m^3/day (six barrels per day) before the test. During the first day of the test, flow was measured by the container-stopwatch method at between 1.3 and 1.6 m^3/day (eight and ten barrels per day). The sonicator was operating in an open hole and oil was flowing out of the casing into the oil collection pit.

October 15. The frequency was increased to the medium frequency level category (1350-1550 Hertz) and the power intensity was raised to ±85%. Thus the output power was raised to 1700 watts (85% of 2000 available watts). The output voltage was raised to an average of 556 volts rms. For this test, the actuator was lowered to the bottom of the pay zone 961 m (3153 ft) and raised 15 cm (six inches) every twenty minutes. The test was run for seven hours.

Using the container-stopwatch approach, production was measured at between 1.6 and 1.9 m^3 (ten and twelve barrels) per day. Visual observations of the well by the project team indicated the presence of more gas in the well on this day compared to the previous day.

October 16. The frequency was lowered by 11%, putting the frequency level for this day's testing in the low category (950-1150 Hertz). For the next day's testing (October 17), the frequency would be raised from the medium category into the medium plus category. Although the project team believed that operating the frequency level in the intermediate and medium categories would result in the largest production increases, the team felt that obtaining "learning-curve" data (Project Objective 2) was critical to the overall success of the project. In addition, by operating in all four frequency categories, the project would successfully complete the work scope that required "sweeping" or changing frequencies while sonicating a specific pay zone. The power intensity was reduced to 55.2% or 1104 watts of output. The output voltage was limited to 524 volts rms. During the previous two days, when the output voltage was above 526 volts rms, a slight deformation in the sine wave was noted on the oscilloscope. This deformation or shoulder appeared just below the peak of the sine wave. Tests were run and the deformation disappeared when the output voltage was below 526 volts rms. The actuator was lowered to the 961-m (3153-ft) horizon and raised 15 cm (six inches) very twenty minutes. The test was run for seven hours.

Using the container-stopwatch approach, production was measured at 1.1 to 1.3 m^3 (seven to eight barrels) per day.

October 17. The frequency was raised from the medium category (1350-1550 Hertz), to the medium plus category (1550-1750 Hertz). The power intensity was raised to 87.4% or 1748 watts of output. The output voltage was 522 volts rms. The actuator was lowered to the 961-m (3153-ft) horizon and raised 30.5 cm (one foot) every twenty minutes. The test was run for three and one-half hours.

Using the container-stopwatch approach, production was measured at 1.2 m^3 (7.75 barrels) of oil per day.

Following Field Test 1, production data were monitored for six weeks. A comparison of production data before and after the test shows the following. For the eighteen days from September 13, 2003 (approximately one month before the field test began) until September 30, 2003 (the last day the well was individually monitored), the Rex Alman #3 well averaged 1.15 m^3 (7.22 barrels of oil) produced per day. From October 1 until October 12 production data were combined with production data from one or two other wells. The well had no recorded production from October 12 through October 17, as the well was disconnected from the oil production piping system during the field test. Following the test, from October 18 through October 25, the well's production was combined with the production from one or two other wells. Starting October 26 and continuing through all of November, the well's production was individually monitored.

For the period from October 26 through October 31, coinciding with the end of the second week following completion of the field test, production was averaging 1.5 m^3/day (9.5 barrels/day). A week later the production had dropped to an average of 1.3 m^3 (8.1 barrels) per day for the three weeks following the field test. After four weeks the total production after the field test had dropped to an average of 1.22 m^3 (7.7 barrels) per day. The production rate continued to drop to an average of 1.19 m^3 (7.5 barrels) by the end of week five and 1.18 m^3 (7.4 barrels) at the end of week six.

In terms of the increase in oil produced expressed as a percent increased, the well was producing 31.5% more oil at the end of the second week after the test than before the test. After the third week, the increase had dropped to 12% and continued downward to 6.6% at the end of week four, 3.8% at the end of week five and 2.2% at the end of week six. Thus a definite increase in production was noted after sonication, but the increase gradually reverted back to pre-sonication production levels.

The project team reviewed the results of Field Test 1 and concluded that a method had to be devised whereby the well could be sonicated and produced (pumped) at the same time. Designing and implementing such a system became a goal for Field Test 2.

The field test and production data from Field Test 1 are included as Appendix A.

Field Test 2, June 28-July 1, 2004

The objective of this field test was to run the sonication system in the optimized mode (as determined from the first field test) for a "continuous" period of time. In the first field test, the system was operated for approximately seven hours per day, then removed from the well. In this test, the tool was to be left downhole, with the goal being to operate the system continually for 40 hours. The well's production would be monitored for 30 days preceding the test and for 30 days following sonication to evaluate the sonication system's ability to increase production. The project team's goal was to increase production by 15%.

A series of discussions was held during the three months preceding the field test to develop an agreed-upon concept and procedure that would allow the sonication unit to be deployed downhole, left in place downhole, and operated after all the tubing and pumping equipment was put back into the well and pumping restarted. In this type of system the well could be stimulated and pumped at the same time. Initially, the project team had hoped to insert the sonication unit through the 7.3 cm (2 7/8 in.) tubing down to the zone to be stimulated. In the well used in the test, the tubing extended 457 m (1500 ft) downhole while the oil was in a formation producing via a perforated zone between 958 m and 961 m (3143 ft and 3153 ft) downhole. The 503 m (1650 ft) between the bottom of the tubing/pump and the oil zone necessitated a tight seal in the tubing/pump to ensure an efficient operation, allowing the pump to bring the oil to the surface. Unfortunately, the power cable was 10 mm (25/64 in. thick (0.39") and precluded a tight seal and efficient vacuum. The idea of inserting the sonication system downhole through the tubing was not possible in this well.

A second approach was presented, whereby the sonication unit would be inserted into the well (after the tubing/pump had been removed), pulled to one side, then the tubing/pump would be reinstalled in the well. The well had no packer between the tubing and the casing, so this option was technically feasible. However, concern was raised that the power cable to the sonicator might be smashed, severed, or made inoperable as it swung "freely" in the casing. Some of the team felt that the cable might wrap around the tubing, eliminating the possibility of raising or lowering the sonication system to do work downhole. A solution was finally reached the week before the test was scheduled. A "pupjoint", a section of tubing much smaller than the normal 15.2-m (50-ft) lengths used in downhole operations would be attached to the end of the tubing and a slot roughly 6.4 cm (2.5 in.) wide and 10.2 cm (4 in.) long cut into the 2.4 m (8 ft) long pupjoint. While still on the land surface, the power cable would be inserted through the slot and connected to the actuator. The sonication unit would be enclosed in a cage to protect the horns at the base of the unit as it was sent downhole. A sinker bar would be added to help stabilize and center the sonication unit as the unit was lowered down to the 958-m (3143-ft) level. Then the tubing, with the pipe joint attached, would be carefully reinserted in the casing. Finally, the pump and sucker rods would be reinserted in the tubing.

June 28. The project team arrived at the site and began working to ensure that everyone - the project team, the site operator, and the field service crew – understood how the system would be assembled and put downhole. The field service crew returned to their facility to prepare the pupjoint and the project team tested the sonication system – power supply, actuator and horns – to ensure its operability.

June 29. At 6:00 am the team assembled on site, and the unit was placed downhole. The tubing (with the pupjoint) and the pump/rods were reinserted in the well. At 7:30 am the sonication unit was started and the power was slowly increased according to a preset schedule. By 7:45 am the unit was operating flawlessly at the optimized parameters. Based on the data from Field Test 1, the project team decided to start this test with the frequency in the intermediate frequency level category (1150-1350 Hertz). The power intensity was set at 79%, thus the output current was 1580 watts; the output voltage was 422 volts rms. The actuator was positioned at the 959-m (3145-ft) level, approximately 0.6 m (2 ft) below the top of the pay zone.

The entire project team left the site late in the afternoon; the system was left operating. One member of the field service crew returned during the night to refill the portable generator with gasoline.

June 30. The unit continued to operate throughout the day. At 8:30 am the project team raised the frequency level to the medium frequency level category (1350-1550 Hertz). The first field test had maximum oil production at the intermediate and medium frequency levels. The project team had decided to initiate operations at the intermediate level and, after 24 hours, switch to the medium level. The power intensity was lowered slightly, to 74.3% or 1486 watts of output current, and the output voltage was 464 volts rms. The actuator was lowered to the 960-m (3150-ft) level, approximately 0.9 m (3 ft) above the base of the pay zone.

The entire project team left the site late in the afternoon and the system was left operating as during the previous night. A member of the field service crew refilled the gas tank on the generator an hour before midnight and reported that the unit was functioning normally.

July 1. Upon arrival at the site, the system was found to be not functioning properly. The output current was down to 29% and the amperage, normally at 2.2-2.3 amps, was down to 1.0 amps. After a series of tests, it was apparent that there was a short circuit, probably a broken wire, in the field-service power unit. The unit had been operating continuously for more than 40 hours until a wire in the field-service power assembly failed early on the morning of July 1. By knowing the amount of gasoline used per hour and by observing the read-out indicator on how much gasoline remained in the generator gas tank, the field service crew was able to back-calculate to determine that the wire bringing power to the actuator failed around 2:30 am Thursday morning. Therefore the project team assumes the unit ran approximately 42.5 hours before the problem occurred.

The sonication system was removed by mid-morning and the tubing/pump reinstalled by the early afternoon

Upon returning home, the sonication unit was tested and functioned properly. Had the power wire not broken, the system most likely would have continued to operate. However, the project team believes that this test was the longest, continuously operated, downhole test of a magnetostrictive sonication system that has been conducted to date.

Production data was reviewed for all of 2004 prior to the test date. Field Management LLC, operator of the entire well field, agreed to separate the production data from the project test well at least one month prior to the scheduled field test date. The well's production data had been combined with production data from two other wells from January 27, 2004 through May 15, 2004. Beginning on May 16, the well was monitored individually. Production averaged 1.0 m^3 (6.3 barrels) per day from May 16 through June 27, 2004. On June 28, the well was opened and the tubing and pump/rods were removed. On June 29, following the downhole installation of the sonication unit, the tubing and pump/rods were reinstalled in the well and pumping began at 9:30 am. On June 30, 1.3 m^3 (eight barrels) of oil production were recorded. On July 1, following the wire break and loss of power to the sonication unit, the tubing and pump/rods were removed from the well so that the sonication unit could be removed. The tubing and pump were reinstalled in the well and production resumed. From July 2 through August 6, 2004, the well averaged 1.2 m3 (7.3 barrels) per day, an increase of 15.87%. Thus the objective of a 15% increase in production for Field Test 2 was met

The field test data and associated production data from Field Test 2 are included in Appendix B of this report.

Discussion

Data were analyzed relative to the objectives of the project, i. e., increased production, system operation, and first-cut economics.

Increased Production

The primary objective of the project was “to evaluate the use of sonication to stimulate oil production in stripper wells”.

In mid-April of 2003, TechSavants, Inc. and Furness-Newburge, Inc. conducted a sonication stimulation test for a private client in California. Production increased by 30% and held for a period of several months. A second well may have been indirectly stimulated, adding to the recorded increase in production. The test included use of a chemical to induce chemical viscosity change in addition to the physical velocity change due to sonication.

In October 2003, the first field test was conducted under this Stripper Well Consortium project. The test well – Rex Alman 3 – had been producing 1.15 m^3 (7.22 barrels) of oil per day up to two weeks before the test. No data on the well’s production was available for the two-week period immediately preceding the test, as the production had been combined with production from one or two other wells. During the test, oil production was recorded by a container-stopwatch method, with production on the first day of testing being between 1.3 and 1.6 m^3 (8 and 10 barrels). The second day's production averaged between 1.6 and 1.9 m^3 (10 and 12 barrels). For the last two days, production averaged 1.1 to 1.3 m^3 (7 to 8 barrels) per day. Following the test, the field crew reconnected the well to combine its production with one or two other wells, as had been done as normal operations. After eight days, the well's production finally was isolated. For the next six days the production level averaged 1.5 m3 (9.5 barrels) a day, an increase of 31.5% more than pre-testing levels. Since the production levels slowly decreased over the next four weeks, one might surmise that the production levels might have been even greater during the eight days for which no individual production data could be recorded. Over the next four weeks, average daily production as computed from cumulative weekly production, gradually decreased with values of 1.29, 1.22, 1.19, and 1.18 m^3 (8.1, 7.7, 7.5, and 7.4 barrels) of oil per day.

For the second field test, the well's production was isolated. Daily production averaged 1.0 m^3 (6.3 barrels) of oil per day for the month before sonication and 1.2 m^3 (7.3 barrels) for a month after sonication, an increase of 15.87%.

The goal of the project team was to increase production by 15%; the data indicate that the goal was met overall and in each of the tests.

As to why production increased, several mechanisms are proposed. While this list is not exhaustive, the likelihood is that a combination of the proposed mechanisms, perhaps not all operating at the same time, accounts for the observed increase in production. Beresnev and Johnson (1994) provide an excellent review of work (especially Russian studies) on elastic wave stimulation and oil production.

The proposed mechanisms for increasing production are:

1. Viscosity change. In parallel with the current project, TechSavants, Furness-Newburge and an oil industry consultant have been working with the University of Alabama at Birmingham on a U.S. Department of Energy Small Business Innovation Research (SBIR) project (SBIR I and II) to evaluate the impact of sonication and selected sonication system parameters – power intensity, horn spacing, frequency levels, time, and chemical additives – on changing the viscosity in three oils with differing API index numbers. One of the oils is from the East Gilbertown Field in Alabama. The SBIR studies gave the project team insights relative to that oil on horn spacing, power intensity and optimum frequency range. Viscosity reductions of 21-24% were measured for the East Gilbertown oil (15-42% for heavier oil) in the SBIR II study, almost entirely due to acoustic energy, as the actuators were not in direct contact with the oil thereby negating any effect of actuator-generated heat on the results. In downhole applications, the heat from the actuators will be dissipated into fluids in the formation (increasing viscosity reduction) and in the casing, as long as the downhole temperature is less than the heat released by the actuator. Viscosity reduction leads to better, more mobile flow, and increasing production.

2. Screen clogging. In many wells, production is inhibited by a buildup of accumulated petroleum-related products, especially asphaltene deposits, on the screens used in an attempt to keep sand and other debris from entering the well and being pumped to the surface. These types of deposits can also reduce the effectiveness of casing perforations. In studies conducted for three industrial clients, TechSavants and Furness-Newburge cleaned metal mesh screens and slotted pipe of buildup, increasing the flow rate in the system. Thus the initial pulse of production might be related in some part to screen or perforation cleaning. A longer-term study would help determine the role of screen cleaning on production.

3. Film removal. Similarly, sonication has the ability to remove organic scale and films from pore spaces, thus increasing the formation's ability to transmit fluids from and through pore spaces. If there is a very thin layer of water between the film and the host rock, the film can be readily broken away from the rock. If there is a layer of oil between the film and the host rock, the task is much more difficult.

4. Gas bubbles. As the formation is sonicated, gas bubbles can form within interstitial/pore liquids. The gases may be a) carbon dioxide, related to the destruction of oil-eating bacteria; b) hydrogen, related to cavitation and the breakdown of formation water; and/or c) organic gases related to chemical reactions between the oil and the acoustic energy of sonication.

5. Change in frictional forces. In many cases the oil might not flow because it is held (at the microscopic level) by capillary forces within the pore spaces in the formation. The acoustic energy put into the formation by sonication may be enough to overcome the adhesive forces of capillary attraction and break the physical bonds between the oil and the formation. If a very thin layer of water exists between the oil and the host rock, the bond is easier to break than if the oil is directly attached to the rock.

While these mechanisms may all have had a role in the increase in production (as may other mechanisms), it was not the design nor intent of this study to identify production-increasing mechanisms. However, at some point, a cause-and-effect study needs to be done to identify and quantify the mechanisms by which acoustic energy increases production. Only then will a truly optimized and targeted sonication system be able to be designed, built, and implemented.

This study answered the original problem statement "Does the use of sonication increase oil production in stripper wells?" with a positive "yes". What is left to answer is the question of "how".

System Operation

The secondary objective of the project was "to develop learning curve data and know-how on methods and techniques of employing a sonication system downhole in an active well".

The following discussion will focus on the sonication system and then on the downhole operation.

Sonication system. The sonication system performed quite well. The project team was concerned about power levels, as running the system at higher levels increases internal wear on the equipment and increases the cost of operating the system. From earlier laboratory and field work, the project team knew that the optimized power range was between 75 and 90%. The first field test was operated at a wide range of power levels to gain experience on interpreting the relationship between power and system performance. For the second test, the power was kept in a limited range, 74-79%.

Output voltage had to be controlled, as too large of a value resulted in distortions to the sine wave on the oscilloscope. Oil production was maximized when the frequency was in the medium category; slightly less production resulted when the frequency levels were in the intermediate category.

For the first test, the equipment was removed from the well at the end of each day's activities and examined for wear. The equipment was housed in a cage to protect it while being inserted downhole and when brought back to the land surface. On one occasion the cage was damaged, and as a result, one of the horns was bent. A modified cage design was developed that appeared to resolve the problem.

In the first test, since each day's activity was done as a separate event, the project team was limited in the amount of time the sonication system could be continuously operated. In addition, because the oil was not collected under on-line pumping conditions, an accurate characterization of the short-term impact of sonication on increased production was difficult to obtain. The second test, therefore, needed to be conducted under conditions where sonication and pumping were occurring at the same time. The project team's activity planned for the second test was "to run a lengthy, continuous test using the conditions that maximized oil production…". The project team set a goal of 40 hours of continuous operation. Even though the test ended when a wire in the power cable/connection system broke, the system had been running for 42.5 hours, thus the goal was met. Had the wire not broken, the unit would have continued to function. However, to the best of the project team's knowledge, this test was the longest, continuous operation of a magnetostrictive sonication system in a pressurized, operating well that has been completed to date.

Downhole operation. Operating the sonication system downhole while pumping/producing oil required developing a unique method for running the system. For this type of well, without a downhole packer, a pupjoint could be attached to the tubing to serve as a guide for centering and controlling the actuator and centering bar. The bar was needed to add weight to the system to help lower the actuator through any oil and water in the well casing. The slot cut into the pupjoint also helped eliminate concerns about the actuator cable wrapping itself around the tubing, thus making raising and lowering of the actuator, as well as precise positioning of the actuator at the desired depth in the pay zone, impossible. Other methods of operation may be required in different downhole situations.

A second downhole issue was the use of a generator to provide power. In situations where electric power is available, the sonication unit should be powered in this manner, rather than using a generator, thereby eliminating the need for someone to stay on site or return to the site to monitor and service the generator. Where power is not available, a generator will be needed.

Another issue that was resolved pertained to positioning the actuator in the pay zone. For the second field test, the system was operating at a depth of 959 m (3145 ft), i.e., the upper half of the pay zone. The project team felt that operating near the top of the pay zone would remove petroliferous material adhering to the perforations, allowing any oil trapped beyond or within the perforations to flow into the well and be pumped to the surface. In addition, the team assumed that the oil would migrate upward in the pay zone, thus the team believed that opening up the perforations near the top of the oil-bearing section would allow more oil to flow into the well, whether water driven or because of viscosity reduction. The test plan called for lowering the sonication device to near the base of the pay zone for days two and three to change the viscosity in the lower half of the formation, allowing the oil to move upward in the section and/or into the well bore. Late on day three and from that point in time throughout the rest of the field test, the unit would be raised back to the upper half of the pay zone to keep the perforations open, the viscosity lowered, and the oil flowing. With the broken wire occurring near the end of day two, the plan was not followed. However, the project team believes the approach of opening the top of the pay zone, then attacking the lower part(s) of the pay zone, and finally returning to the top of the pay zone will maximize production in acoustically stimulated wells.

Economics

The third objective of this study was "to collect first-cut data on economics of the process". Because this was primarily a research study, many of the costs were first-time costs. In addition, because one of the objectives of this study was to obtain data on operating parameters, a comparison of the project's actual costs with projected future costs (in a non-research mode) is required. Labor support was the largest cost. Extensive costs were realized during the first test, as a result of having a field operating crew and a wireline truck/field service crew on site for the duration of the test. For the second test, the on-site manpower was reduced in number and in the time present on site.

The project team projects the following costs to install a downhole sonication system where the actuator will be left downhole and operated as needed:

Length of time = two days. Depth = 915-1219 m (3000-4000 feet).

Labor: field crew and wireline truck/crew	$ 5,000
Cost of sonication unit plus backup unit	$ 24,000
Installation cost (manpower and expenses)	$ 7,000
Total	$ 36,000

These costs may be lowered as the number of units sold increases.

With the price of a barrel of oil rising and the uncertainty therein, one can assume that the following payback scenarios are speculative. If production is increased two barrels a day, and the amount received by the well owner is $20 per barrel, payback is achieved (just on the increase in production) in 900 days or approximately 30 months. At $30/barrel, payback takes 20 months; and at $40/barrel, 15 months. If production is increased by 3 barrels/day, payback goes down to 20 months for $20 oil, 13 months for $30 oil, and 10 months for $40 oil.

CONCLUSIONS

This project evaluated the impacts of the use of sonication to stimulate oil production in the East Gilbertown Field, West-Central Alabama. The project's primary objective was to determine and document if downhole sonic (acoustic) stimulation resulted in increased oil production. Related objectives were to develop information and know-how on deploying a sonication system downhole and to develop first-cut economic data. All of the project's objectives were accomplished.

The following conclusions were reached:

1. Sonic (acoustic) stimulation increased production in each of the two field tests by a minimum of 15% to as large as 30% for an initial period, then production returned to levels slightly higher than original levels within a few weeks. The data showed that sonication did have an impact on production, but the impact was related to operating the sonication system. When sonication was stopped, the impact on increased production gradually abated.

2. The sonication system (power source, actuator, and horn) was operated continuously for more than 40 hours. This period of time was the longest, continuously run test to date and demonstrated that the actuator and horn could be left downhole to operate for extended periods of time. This fact is critical to the future commercial development of oil well stimulation by sonication, as the field tests made it apparent that the wells would have to be stimulated at selected intervals (periodically to continuously) by an actuator left downhole.

3. A method was devised and successfully employed that allowed sonication and fluid production by pumping to occur simultaneously. Development of this method also was critical to the future commercial success of the technology, as the flexibility of periodic sonication with continuous pumping maximizes oil production while minimizing the cost of field operations.

4. Data on optimum frequency levels and power intensities were developed. While these data are useful as guidelines for applying sonication technology in a certain type of sandstone lithology, more data are necessary from other types of geologic conditions before optimization of a sonication system can be achieved.

5. Very preliminary data on the economics of the system indicate that payback of the system's cost is relatively quick. Depending on the number of cubic meters or barrels of oil per day of increased production, plus the price the well owner gets for the oil, payback times for a deployed sonication system could range from 30 to as little as 10 months, if just 0.32-0.48 additional m3 (2-3 additional barrels) of oil are produced per day.

The following recommendations are made with the idea of rapidly commercializing the technology:

RECOMMENDATIONS

1. The tests run to date have been of limited duration. Although the technology and methodology have now been developed and demonstrated to the point where both sonication and pumping can be operated simultaneously, it is now time for a series of long-duration field tests. At a minimum, tests should be run for periods of two, four, and six weeks, with simultaneous, continuous sonicating and pumping.

2. A second series of tests should be run where the sonication system is operated intermittently while pumping is continuous, for a period of six weeks. Special concern should be taken to monitor production levels related to the intermittent use of the sonication system.

3. A series of tests should be run using chemical additives in conjunction with sonication to reduce the viscosity of the oil as another means to increase production in stripper wells. Based on data from the DOE funded SBIR II study "Acoustic Energy: An Innovative Technology for Stimulating Oil Wells" being conducted by two members of the project team (TechSavants, Inc., and Furness-Newburge, Inc.) plus the University of Alabama at Birmingham and Aarmco, an oil industry consulting group, the chemicals used in the study reduced the viscosity of API 8° oil from 13-40% in addition to the 15-42% reduction related to sonication. The effects of using chemicals plus sonication to increase oil production from stripper wells needs to be evaluated in closely monitored field tests.

4. New instrumentation and equipment need to be developed to increase the efficiency and performance of the sonication system. The next generation of actuators needs to be developed specifically for downhole use, i.e., for operating in high-temperature, high-pressure, corrosive environments. The power of the actuators must be increased, the broadband frequency capabilities expanded, and a higher efficiency method for directing and transferring the acoustic energy into the oil-bearing formation must be developed.

5. Data collection needs to be enhanced through the development of accurate, robust, and reliable sensors. New passive photonic sensors need to be developed and integrated with the actuator into a downhole package to measure pressure waves (pressure levels and gradients), temperatures, and flow rates of fluids of various densities.

6. One of the critical factors in evaluating the effectiveness of acoustic stimulation on stripper well production is a determination of the lateral extent of the input stimulus. Ultra-low frequency sound (20-100 Hertz) is known to travel laterally for several miles. What is unknown is how far the impacts of sonication – the acoustic wave – extend before becoming ineffective, at the frequencies necessary to increase oil production. If it can be shown that an acoustic wave has enough energy to impact (increase production) in nearby wells, the value of the technology dramatically increases and the operating costs to produce a barrel of oil decrease dramatically.

Deploying geophones downhole alongside passive wave sensors (recommendation 5) needs to be integrated into the long-term field tests recommended in items 1-3 above.

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APPENDIX A

FIELD TEST 1 DATA

APPENDIX A

Table A-1 Test Data for October 14, 2003

Depth (ft)	Start	End	Duration	Frequency	Output %	Volts
3,142.0	8:17	8:22	Warm-up	Intermediate	20.3	222
3,142.0	8:22	9:00	Warm-up	Intermediate	64.1	540
Depth (ft)	**Start**	**End**	**Duration**	**Frequency**	**Output %**	**Volts**
3,143.0	9:00	9:23	0:23	Intermediate	66.4	546
3,143.5	9:23	9:43	0:20	Intermediate	66.8	548
3,144.0	9:43	10:02	0:19	Intermediate	66.7	546
3,144.5	10:02	10:22	0:20	Intermediate	66.9	546
3,145.1	10:22	10:42	0:20	Intermediate	67.1	546
3,145.4	10:42	11:02	0:20	Intermediate	67.2	546
3,146.0	11:02	11:21	0:19	Intermediate	67.3	548
3,146.5	11:21	11:41	0:20	Intermediate	67.3	548
3,147.0	11:41	12:01	0:20	Intermediate	67.4	548
3,147.5	12:01	12:20	0:19	Intermediate	67.5	548
3,147.9	12:20	12:40	0:20	Intermediate	67.5	548
3,148.4	12:40	12:59	0:19	Intermediate	67.5	548
3,149.0	12:59	13:19	0:20	Intermediate	67.5	548
3,149.4	13:19	13:40	0:21	Intermediate	67.4	548
3,150.0	13:40	14:00	0:20	Intermediate	67.3	548
3,150.5	14:00	14:20	0:20	Intermediate	67.2	548
3,151.0	14:20	14:40	0:20	Intermediate	67.2	548
3,151.5	14:40	14:59	0:19	Intermediate	67.1	548
3,152.0	14:59	15:19	0:20	Intermediate	67.0	548
3,152.5	15:19	15:39	0:20	Intermediate	67.2	548
3,153.0	15:39	16:00	0:21	Intermediate	67.3	548

NOTE: Output Current = Output % multiplied by 2000 watts. To convert depth in feet to depth in meters, multiply by 0.3048.

Table A-2 Test Data for October 15, 2003

Depth (ft)	Start	End	Duration	Frequency	Output %	Volts
3153.0	7:36	7:45	Warm-up	Low	15.2	204
3153.0	7:45	7:54	Warm-up	Low	58.2	542
3153.0	7:54	8:00	Warm-up	Medium	81.0	548
Depth (ft)	**Start**	**End**	**Duration**	**Frequency**	**Output %**	**Volts**
3153.0	8:00	8:20	0:20	Medium	82.8	550
3152.5	8:20	8:41	0:21	Medium	82.7	552
3152.0	8:41	9:00	0:19	Medium	83.1	550
3151.5	9:00	9:22	0:22	Medium	83.6	554
3151.0	9:22	9:40	0:18	Medium	84.2	556
3150.4	9:40	10:00	0:20	Medium	84.7	556
3149.5	10:00	10:20	0:20	Medium	84.7	556
3149.0	10:20	10:40	0:20	Medium	84.8	556
3148.5	10:40	11:01	0:21	Medium	85.0	556
3147.9	11:01	11:21	0:20	Medium	85.2	556
3147.3	11:21	11:40	0:19	Medium	85.3	558
3147.0	11:40	12:00	0:20	Medium	85.4	558
3146.4	12:00	12:20	0:20	Medium	85.5	558
3146.0	12:20	12:40	0:20	Medium	85.6	558
3145.5	12:40	13:00	0:20	Medium	85.7	558
3145.0	13:00	13:20	0:20	Medium	85.5	558
3144.4	13:20	13:40	0:20	Medium	85.4	558
3144.0	13:40	14:00	0:20	Medium	85.3	558
3143.5	14:00	14:21	0:21	Medium	84.8	556
3143.0	14:21	14:40	0:19	Medium	84.8	556
3142.5	14:40	15:00	0:20	Medium	84.7	556

NOTE: Output Current = Output % multiplied by 2000 watts. To convert depth in feet to depth in meters, multiply by 0.3048.

Table A-3 Test Data for October 16, 2003

Depth (ft)	Start	End	Duration	Frequency	Output %	Volts
3153.0	7:50	7:55	Warm-up	Low	15.2	212
3153.0	7:55	8:00	Warm-up	Low	36.7	520
Depth (ft)	**Start**	**End**	**Duration**	**Frequency**	**Output %**	**Volts**
3153.0	8:00	8:30	0:30	Low	54.6	526
3152.5	8:30	9:00	0:30	Low	54.6	526
3152.0	9:00	9:20	0:20	Low	54.5	522
3151.5	9:20	9:40	0:20	Low	54.7	524
3151.0	9:40	10:00	0:20	Low	54.8	524
3150.5	10:00	10:20	0:20	Low	55.0	524
3150.0	10:20	10:40	0:20	Low	55.4	524
3149.6	10:40	11:01	0:21	Low	55.4	524
3149.1	11:01	11:20	0:19	Low	55.5	524
3148.5	11:20	11:40	0:20	Low	55.6	524
3148.0	11:40	12:00	0:20	Low	55.8	524
3147.5	12:00	12:20	0:20	Low	55.7	524
3147.0	12:20	12:40	0:20	Low	55.3	524
3146.5	12:40	13:00	0:20	Low	55.3	524
3146.0	13:00	13:20	0:20	Low	55.2	524
3145.5	13:20	13:40	0:20	Low	55.2	524
3145.0	13:40	14:00	0:20	Low	55.2	524
3144.5	14:00	14:20	0:20	Low	55.3	524
3144.0	14:20	14:40	0:20	Low	55.2	524
3143.4	14:40	15:00	0:20	Low	55.3	524
3143.0	15:00	15:20	0:20	Low	55.3	524

NOTE: Output Current = Output % multiplied by 2000 watts. To convert depth in feet to depth in meters, multiply by 0.3048.

Table A-4 Test Data for October 17, 2003

Depth (ft)	Start	End	Duration	Frequency	Output %	Volts
3153.0	7:23	7:35	Warm-up	Medium +	14.8	142
Depth (ft)	**Start**	**End**	**Duration**	**Frequency**	**Output %**	**Volts**
3153.0	7:35	8:00	0:25	Medium +	85.0	518
3152.0	8:00	8:20	0:20	Medium +	86.7	522
3150.9	8:20	8:40	0:20	Medium +	86.8	522
3149.9	8:40	9:00	0:20	Medium +	87.2	522
3148.9	9:00	9:20	0:20	Medium +	87.7	522
3147.9	9:20	9:40	0:20	Medium +	87.7	522
3146.9	9:40	10:00	0:20	Medium +	88.0	522
3146.0	10:00	10:20	0:20	Medium +	88.1	522
3145.0	10:20	10:40	0:20	Medium +	88.3	524
3144.0	10:40	11:00	0:20	Medium +	88.4	524

NOTE: Output Current = Output % multiplied by 2000 watts. To convert depth in feet to depth in meters, multiply by 0.3048.

Table A-5 Production Data Associated with Test 1

Production Source	Date	Production (barrels/day)
Rex Alman #3	9/13/2003	2
..	9/14/2003	3
..	9/15/2003	6
..	9/16/2003	5
..	9/17/2003	7
..	9/18/2003	6
..	9/19/2003	8
..	9/20/2003	8
..	9/21/2003	8
..	9/22/2003	8
..	9/23/2003	8
..	9/24/2003	8
..	9/25/2003	9

Production Source	Date	Production (barrels/day)
Rex Alman #3	9/26/2003	9
¨	9/27/2003	9
¨	9/28/2003	9
¨	9/29/2003	8
¨	9/30/2003	9
Combined with Hubert Mosley#3	10/1/2003	27
¨	10/2/2003	33
¨	10/3/2003	37
¨	10/4/2003	37
¨	10/5/2003	30
¨	10/6/2003	40
¨	10/7/2003	32
¨	10/8/2003	30
¨	10/9/2003	28
¨	10/10/2003	32
¨	10/11/2003	23
Test Well Shut Down	10/12/2003	Down – Test Period
¨	10/13/2003	Down – Test Period
¨	10/14/2003	Down – Test Period
¨	10/15/2003	Down – Test Period
¨	10/16/2003	Down – Test Period
¨	10/17/2003	Down – Test Period
Combined with Hubert Mosley#3	10/18/2003	60
¨	10/19/2003	28
¨	10/20/2003	27
¨	10/21/2003	28
¨	10/22/2003	28
¨	10/23/2003	28
¨	10/24/2003	28
¨	10/25/2003	13

Production Source	Date	Production (barrels/day)
Rex Alman #3	10/26/2003	9
¨	10/27/2003	9
¨	10/28/2003	9
¨	10/29/2003	10
¨	10/30/2003	10
¨	10/31/2003	10
¨	11/1/2003	3
¨	11/2/2003	8
¨	11/3/2003	7
¨	11/4/2003	7
¨	11/5/2003	9
¨	11/6/2003	7
¨	11/7/2003	7
¨	11/8/2003	7
¨	11/9/2003	7
¨	11/10/2003	7
¨	11/11/2003	8
¨	11/12/2003	6
¨	11/13/2003	8
¨	11/14/2003	6
¨	11/15/2003	8
¨	11/16/2003	7
¨	11/17/2003	7
¨	11/18/2003	8
¨	11/19/2003	5
¨	11/20/2003	7
¨	11/21/2003	7
¨	11/22/2003	7
¨	11/23/2003	7
¨	11/24/2003	7

Production Source	Date	Production (barrels/day)
¨	11/25/2003	7
¨	11/26/2003	7
¨	11/27/2003	7
¨	11/28/2003	6
¨	11/29/2003	7
¨	11/30/2003	6

NOTE: To convert from barrels of oil per day (barrels/day) to cubic meters per day (m^3/day) multiply by 0.1589.

APPENDIX B

FIELD TEST 2 DATA

APPENDIX B

Table B-1 Test Data for June 29 – July 1, 2004

Depth (ft)	Time	Frequency	Output %	Volts
		June 29, 2004		
3144.9	7:30	Intermediate	65.7	352
3144.9	8:00	Intermediate	80.2	420
3149.0	9:10	Intermediate	79.8	422
3147.0	10:30	Intermediate	79.9	422
3144.9	10:45	Intermediate	79.8	422
3144.9	11:30	Intermediate	79.8	422
3144.9	12:00	Intermediate	79.1	422
3144.9	12:30	Intermediate	79.0	422
3144.9	13:00	Intermediate	79.2	422
3144.9	13:30	Intermediate	79.0	422
3144.9	14:00	Intermediate	79.1	422
3144.9	14:30	Intermediate	79.1	422
3144.9	15:00	Intermediate	79.1	424
		Test ran continuously through the night.		
		June 30, 2004		
3144.9	7:00	Intermediate	78.0	424
3144.9	7:30	Intermediate	78.9	424
3144.9	8:00	Intermediate	77.7	424
3144.9	8:30	Medium	75.8	476
3150.0	9:00	Medium	73.8	464
3150.0	9:30	Medium	73.9	464
3150.0	10:00	Medium	73.6	464
3150.0	10:30	Medium	73.5	464
3150.0	11:00	Medium	73.5	464
3150.0	11:30	Medium	76.0	464
3150.0	12:00	Medium	76.0	464
3150.0	12:30	Medium	73.3	464
3150.0	13:00	Medium	73.1	464

Depth (ft)	Time	Frequency	Output %	Volts
3150.0	13:30	Medium	73.2	464
3150.0	14:00	Medium	74.9	464
3150.0	14:30	Medium	75.5	464
Power Supply wire broke at 2:30 (estimated).				
July 1, 2004				
3150.0	8:00	Medium	29.0	464

NOTE: Output Current = Output % multiplied by 2000 watts. To convert depth in feet to depth in meters, multiply by 0.3048.

Table B-2 Production Data Associated with Test 2

Production Source	Date	Production (barrels/day)
Rex Alman #3	5/16/2004	8
"	5/17/2004	5
"	5/18/2004	8
"	5/19/2004	5
"	5/20/2004	8
"	5/21/2004	7
"	5/22/2004	8
"	5/23/2004	5
"	5/24/2004	7
"	5/25/2004	8
"	5/26/2004	7
"	5/27/2004	5
"	5/28/2004	7
"	5/29/2004	8
"	5/30/2004	8
"	5/31/2004	7
"	6/1/2004	2
Well Not Producing	6/2/2004	0
Rex Alman #3	6/3/2004	5

Production Source	Date	Production (barrels/day)
Rex Alman #3	6/4/2004	5
"	6/5/2004	7
"	6/6/2004	8
"	6/7/2004	5
"	6/8/2004	3
"	6/9/2004	5
"	6/10/2004	7
"	6/11/2004	7
Pump Equipment Problem	6/12/2004	3
Rex Alman #3	6/13/2004	5
"	6/14/2004	5
"	6/15/2004	7
"	6/16/2004	7
"	6/17/2004	5
"	6/18/2004	2
"	6/19/2004	2
"	6/20/2004	7
"	6/21/2004	10
"	6/22/2004	8
"	6/23/2004	7
"	6/24/2004	8
"	6/25/2004	8
"	6/26/2004	10
"	6/27/2004	8
Well Shut Down Preparation for Test	6/28/2004	0
Tool Placed in Well	6/29/2004	0
Production	6/30/2004	8
Tool Removed from Well Production Restarted	7/1/2004	0
Rex Alman #3	7/2/2004	7

Production Source	Date	Production (barrels/day)
Rex Alman #3	7/3/2004	10
..	7/4/2004	10
..	7/5/2004	7
..	7/6/2004	8
..	7/7/2004	7
..	7/8/2004	7
..	7/9/2004	8
..	7/10/2004	10
..	7/11/2004	8
..	7/12/2004	7
..	7/13/2004	7
..	7/14/2004	7
..	7/15/2004	5
..	7/16/2004	7
Well Down – Electrical Problem	7/17/2004	0
Rex Alman #3	7/18/2004	5
..	7/19/2004	8
..	7/20/2004	5
Well Down – Line Problem	7/21/2004	3
Rex Alman #3	7/22/2004	10
..	7/23/2004	7
..	7/24/2004	7
..	7/25/2004	7
..	7/26/2004	5
..	7/27/2004	8
..	7/28/2004	8
..	7/29/2004	8
..	7/30/2004	8
..	7/31/2004	8
..	8/1/2004	7

Production Source	Date	Production (barrels/day)
Rex Alman #3	8/2/2004	7
¨	8/3/2004	5
¨	8/4/2004	8
¨	8/5/2004	10
¨	8/6/2004	7
¨	8/7/2004	3

NOTE: To convert from barrels of oil per day (barrels/day) to cubic meters per day (m^3/day) multiply by 0.1589.

APPENDIX C

PHOTOGRAPHS

Photo 1 Horn Design used in Field Tests. The Lower Portion of the Actuator is also Shown.

Photo 2 Horn, Actuator, Connector, Centering Device and Bottom of Sinker Bar Before Inserting into a Test Well in Gilbertown, Alabama

Photo 3 Tool Being Lowered into Well for First Test on October 14, 2003.

Photo 4 Examining Tool for any Signs of Wear or Damage Immediately after the Completion of the First Day of Testing on October 14, 2003.

Photo 5 No Wear or Damage to the Sonic Tool Observed after the Completion of Testing on October 14, 2003.

Photo 6 One of the Bars of the Lower Centralizer was Bent during October 15, 2003 Testing.

Photo 7 Two Screws Holding One Bar to the Top Centralizer Came Loose during October 15, 2003 Testing.

Photo 8 Note that the Upper Fin was Slightly Bent during Testing on October 15, 2003.

Photo 9 One of the Four Quadrants of the Upper Fin was Slightly Bent during the Testing on October 15, 2003.

Photo 10 Bubbles in Oil during October 15, 2003 Testing.

Photo 11 Oil Flowing from Wellhead during Testing on October 15, 2003.

Photo 12 Sonication Tool Being Lowered into Well the Morning of October 16, 2003

Photo 13 Cedarhill Operating Company's Oil Pit and Service Truck.

Photo 14 Cedarhill's Oil Pit Near the Wellhead.

Photo 15 The Cage Protecting the Sonication Tool was Modified for the Second Field Test. Here the Cage is being Attached to the Actuator-Horn Apparatus.

Photo 16 Power Supplies Connected in Series to Control Electrical Power Supplied to Downhole Tool.

Photo 17 Pup Joint Showing Slot that was Cut to Allow Insertion of Wires Connecting to the Sonication Tool.

Photo 18 Inserting Pump into Tubing Within the Well Used for Field Test 2.

Photo 19 Pup Joint after Removal from the Well at the Conclusion of Field Test 2.

Title Page

Report Title: Low Cost Wireless Communications based Pressure and Temperature Gauge for Production Optimization Applications

Type of Report: Final Report

Project Report Period: Start Date – July 01, 2003

End Date- May 15, 2004

Principal Author: Paul Tubel

Date Report was issued: May 15, 2004

Subcontractor No. 2553-TT-DOE-1025

Submitting Organization: Tubel Technologies, Inc.

4800 Research Forest

The Woodlands, TX 77381

Disclaimer

Abstract

The goal of the project was to develop a low cost gauge based on an existing commercial high end wireless gauge developed by Tubel Technologies to monitor pump performance; monitor fluid level to optimize lifting operation and to lower lifting costs; monitor bottom hole pressure to optimize drawdown and for build up tests. The build up tests will provide reservoir pressure information for the optimization of the hydrocarbon production. This project provided the research, develop and test a lower cost, high reliability, real time wireless gauge composed of compressional acoustic waves based wireless communications transmitting data in real time through the production tubing, strain gauge pressure sensor and a temperature sensor for measurements of downhole pressure and temperature, surface module to acquire the transmitted signal from downhole and process the data. The new wireless gauge can be deployed anywhere in a production and injection well. The gauge utilizes low power electronics and sensor technology to acquire and process in real time well data related to production and formation parameters. A battery pack provides power for operation of the system downhole.

All goals for the project were achieved and a low cost wireless real time downhole gauge system was developed and tested successfully.

Table of Content

List of Graphical Materials

Introduction

The DoE/Penn State sponsored project provides the ability of automating and optimizing the production of hydrocarbons from Stripper Wells. The increase in hydrocarbon prices due to the higher consumption levels of petroleum and natural gas throughout the world has created the need to extract the greatest amount of hydrocarbons from existing wells at the most efficient way possible.

The new Wireless Real Time Low Cost Downhole Gauge system can be deployed in wellbores permanently or for short periods of time for service applications. The system can be used to monitor formation parameters in pressure build up tests during production and also be used to monitor the health of a pump used to lift the hydrocarbon from downhole. The early indication that the pump is not performing well will allow the operator to schedule an intervention in the well before the pump fails preventing a loss of production.

The Wireless Gauge can also be used to optimize production by monitoring fluid levels during the lifting process to assure that the pump is only in operation when the fluid accumulation is optimum for lifting. That process will decrease the fuel cost for lifting the hydrocarbon and minimizing the wear on the pump.

The system can also be used for service applications such as frac jobs, acid jobs, gravel packing and pressure build up tests. The utilization of real time wireless gauges in service applications will replace memory gauges and provide the operator with information while the task is being performed in the wellbore. The pressure and temperature information will help the optimization of the frac jobs to assure that the frac work is done properly to maximize production. The pressure build up tests performed in real time will allow the operator to assure that the data is being provided as the test is being performed and provide the option to terminate the test earlier than scheduled if the required data necessary to perform the formation evaluation is available before the test is completed. The early termination of the test will allow the operator to re-start production sooner.

The Wireless Real Time Gauge system is a tool used inside the wellbore to provide pressure and temperature information from the annulus and tubing sections of the wellbore. The information obtained inside the well is processed by the electronics and transmitted to the surface using acoustic waves traveling through the production tubing carrying digital information related to pressure and temperature data obtained by the gauge. The system is composed of 2 pressure and temperature gauges, an electronics module provided analog to digital conversion, data processing and data frame setup, an acoustic generator driver and an acoustic generator. The mandrel is composed of 4140 steel tubing and a pressure housing to seal the system and to maintain the electronics at a atmospheric pressure level. A surface acoustic to electrical converter and a data processing surface panel complete the system.

Figure 1. Donwhole Real Time Wireless Pressure and Temperature Gauge

Executive Summary

The Low Cost Wireless Communications based Pressure and Temperature Gauge for Production Optimization Applications project was completed successfully. The project created a new wireless gauge for low end applications and for small casing sizes. The highlights of the accomplishments for this project are listed below.

1. The project achieved its goal of developing a low cost wireless gauge for downhole applications. The system transmit data from downhole using compressional acoustic waves traveling through the production tubing to the surface where it is decoded and processed in real time.
2. The project allow Tubel Tech to develop a wireless gauge that can be deployed in casing diameters as small as 4 ½ inches.
3. The system works to 125^0 Celsius and 6,000 psi.
4. The Wireless Gauge project developed a new sapphire pressure sensor that is small enough to be placed in a 3 .5 inches mandrel.
5. The new electronics is capable of power management to provide 3 years life inside the well transmitting data every 5 minutes.
6. The new Wireless Gauge was able to generate 2.5 times more energy at the production tubing than the existing commercial Tubel Technologies 2 7/8 inches tubing wireless gauge.
7. The newly developed mandrel is composed of 2 sections: One module houses the sensors and the other module houses the remainder of the wireless gauge. The 2 module tool is easily manufactured and at a low cost.

8. The acoustic data transmission distance between the transmitter and receiver from downhole to the surface can reach 10,000 ft.
9. The system has a small diameter for applications with coil tubing.

Experimental

Experimental Apparatus –

The tests performed during this project were:

1. Dead weight tester with a pressure accuracy of 0.015% of full scale for testing and calibration of the pressure gauge.
2. Pressure Chamber to test the entire tool. The chamber was capable of operating to pressures up to 15,000 psi and it used a closed loop control to assure that the pressure exerted onto the tool was correct.
3. Production tubing deployed at the surface for evaluation of the acoustic wave attenuation. The 1,000 ft of 3 ½ inch tubing was deployed in a field in the Dallas area with standard tubing threads for connection to the wireless gauge.
4. Temperature tests were performed on the electronics module for long term operation of the system.

Experimental and Operating Data –

The results of the tests were as following:

1. The deadweight test results indicated that the pressure sensors operated linearly with temperature. The results also indicated that the tool was able to maintain 0.1% accuracy with the sensors and a 1.25 psi of resolution for a 5,000 psi sensor.
2. The pressure chamber tests indicated that the tool does not collapse or is damaged in anyway when 5,000 psi pressure is exerted onto the wireless gauge.

3. The pipe tests were obtained by placing the wireless gauge at one end of the tubing and the receiver on the other end of the pipe. An accelerometer driver with an oscilloscope was used to measure the acoustic energy on the receiver end of the pipe. Multiple frequencies were used to evaluate the acoustic attenuation through the tubing. The results indicated that the attenuation was approximately 10 db/1000 ft.
4. The electronics were tested for temperature performance and reliability and the results were successful. A new flash processor was qualified for downhole applications that allow the software inside the tool to be modified without having to replace the microprocessor.

Results and Discussion

The low cost wireless gauge development has been completed and the results have surpassed all performance expectations at Tubel Tech. All modules are working properly and the entire system has shown to perform better than previous systems developed by Tubel. The first prototype should be deployed in a well in early June 2004. The test will be performed using a coil tubing for the transmission of the real time data from downhole to the surface. The application will be a frac job in a coalbed methane application.

The low cost wireless gauge system has some unique features developed for this project including the following:

1. A 2 piece tool mandrel instead of 3 modules which decrease the cost and increase the reliability by eliminating a metal to metal seal connection.

2. Small diameter pressure gauges reduces the overall diameter of the tool allowing the system to have 3.675 OD and can be used in wells with 4 ½ inches casing.

3. The system uses a flash memory based microprocessor which allows the software for the downhole tool to be upgraded without having to remove the processor from the PC Board.

4. The system uses a new technique for acoustic data transmission developed for the high pressure high temperature wireless gauge DoE project which will reduce the amount of energy required to transmit data to the surface from downhole.

5. The system is low cost and high performance.

6. The system can be used in service applications for temporary deployment in wells.

Conclusion

The conclusions and achievements for this project are as following:

- The entire tool has been developed successfully. The entire system performance has met and exceeded all specifications created for the system in the beginning of the project.
- The wireless gauge is low cost and can be used in stripper well applications for permanent and service applications.
- The system can operate in casing sizes as small as 4 ½ inches.
- The system can provide data at high speed and operate at pressures in excess of 5,000 psi.
- The system software will allow the data to be recorded in memory continuously as well as to provide real time information for service applications.
- The system has a new power reduction module to minimize battery power to extend the life of the system in the wellbore.
- The system has 2 pressure and temperature gauges that are deployed to measure tubing and annulus pressures in real time. The new pressure sensor was developed to minimize its diameter to fit in the outer diameter of the wireless gauge.

- The surface system was developed to process the data in real time and display the information as well as to store the information for later retrieval into a PC or data network.

References

There are no references related to this project and work.

Bibliography

There is no bibliography related to the work being performed.

List of Acronyms and Abbreviations

There are no acronyms or abbreviations in this report.

Appendices

System Specifications

KEY FEATURES

- Wireless Communications
- High Reliability
- Operation up to 125^0C
- From 0 to 5,000 PSI range
- Data Rate 10 bits/sec
- Life Expectancy 3 years
- Built-in Pressure Gauges
- Battery Operated

Wireless Reservoir Monitoring Tool

A new low cost technology has been developed to transmit data from inside a wellbore to the surface without cables. This new system employs stress waves in the pipe string to communicate throughout the wellbore. The system has built-in pressure and temperature gauges for tubing and annulus measurements.

The new low cost wireless system does not block fluid flow providing full bore access. The tool was developed for production automation and optimization in coal bed and stripper well applications. It can be deployed in production wells to measure and transmit production parameters to the surface without a hardwired connection. It is also used for bottom hole pressure and temperature measurements for frac jobs, drillstem testing and gravel pack.

APPLICATIONS

- Coal bed Methane
- Production Permanent Monitor
- Liner Pressure Drop Monitoring
- Production Automation
- Intelligent Well Applications
- Artificial Lift Automation
- Gravel Pack monitoring
- Frac Pressure Monitoring

SPECIFICATIONS

Transmission range :	6,000 ft (2,000 meters)
Rate	Up to 10 bits per second
Tubing Size	2 3/8 inches (2 7/8, 3 ½ inches available)
Operating temperature :	-20 to 125 °C
Signal type	Stress Waves
Power	Battery
Life Expectancy	Based on data rates and battery size
Pump Noise	Immune
Maximum External Pressure	6,000 psi
Pressure Gauge	0- 5,000 psi
Pressure Resolution	12 bits (24 bits available)
Pressure Accuracy	0.1% of FS
Pressure Measurements	Annulus and Tubing
Length	82 inches
Tool OD	3.675 inches
Tool ID	1.81 inches
Burst Pressure	7,000 psi
Max Tension	45,000 lbs
Max Torque	1,200 ft-lb
Std Connection	2 3/8 NU 10rd

PVT Study of the Interaction of Nitrogen and Crude Oil

Final Report
during the Period 7/1/2003 to 12/31/2004

By

A. Abboud, D.K. Johnson and R.W. Watson

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The Department of Energy and Geo-Environmental Engineering
The Energy Institute

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DISCLAIMER

ABSTRACT

The objective of this investigation is to study the impact of the injection of nitrogen/oxygen mixtures on the physical properties of crude oil and to determine its effect on oil composition. The mid-continent grade crude oil used in this study was obtained from the Big Andy field in Central Kentucky. This field is currently realizing enhanced oil recovery using nitrogen/oxygen injection.

A test matrix of 3 different injection mixtures was used. The mixture consisted of 100 % nitrogen, 97 % nitrogen - 3% oxygen, and 86 % nitrogen - 14% oxygen. Six cycles of injection followed by a "soaking phase" and then withdrawal were performed for each gas mixture. Results obtained from laboratory PVT studies were used to develop a phase behavior model.

The results of the study indicated that striping of the crude oil (methane through decane plus) was being realized. The first injection using 100 % nitrogen indicated that the lighter components of the crude oil (methane through butane) were stripped from the crude oil. The volume underwent a 5 % shrinkage after 6 cycles for the 100 % N_2 test matrix. The results obtained for the other injection mixtures (97-3 % N_2O_2 and 86-14 % N_2O_2) showed shrinkage of 4 % volumetrically. The results obtained also indicated an increase in viscosity and density for all three injection mixtures after 6 injection cycles.

A phase behavior package has been able to model the results obtained from the PVT laboratory experiments. The interaction coefficients were tuned manually to best fit the results obtained from the crude oil's composition. The trend in results was very similar to those obtained from the PVT data. The model has shown that for a given initial mass of crude oil, there was 3 % shrinkage for a total of 8 cycles when injecting 100 % N_2. When varying the composition, the shrinkage did not show any significant variation from those obtained initially.

From the results obtained through the PVT cell and the phase behavior model, perhaps the most significant observations are the role of oxygen in the injected gas on the physical properties of the crude oil, and the vaporization of the crude oil. It has been observed that the presence of oxygen does not tend to increase the viscosity of the crude oil when compared to nitrogen alone.

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INTRODUCTION

1.1 Introduction

Improved oil recovery techniques (IOR) have increased in application over the past few decades because of lower production volumes and rising oil prices. Generally, oil companies must take into account two major factors when considering IOR processes. First, the feasibility of the technique to the specific field must be evaluated. Second, and most importantly, the economic soundness of the project must justify the application of the technique itself. The latter is primarily dependent upon regional oil prices and the cost/benefit of the additional oil recovery.

Among the IOR techniques used today, the most widely practiced in the United States are waterflooding, steamflooding and CO_2 injection. All of these methods have early applications that date back to the 1930’s through the1950’s. This is especially true of CO_2 and steam injection. Throughout the last decade, the application of nitrogen cyclic injection for immiscible processes, primarily pressure depleted reservoirs, has increased. The recovery process is very similar to that of steam stimulation practiced in the early 1930’s. Whereas steam is used for heavy crudes, nitrogen cyclic injection is being used for comparatively light oils under low pressure conditions.

Despite the increase in the use of nitrogen for improved oil recovery, there has been little research supporting the use of it in shallow low pressured reservoirs containing comparatively light crude oil. Although nitrogen injection has shown promise as a technique, methods for screening reservoirs for applicability are necessary prior to implementation of the cyclic process.

1.2 Objective of the Study

The objective of this study is to evaluate the nitrogen huff and puff (i.e. cyclic injection) process in a dual porosity reservoir that is pressure depleted. The field is located in Eastern Kentucky and is operated by an independent oil company, Bretagne. To accomplish this objective, a PVT cell was fabricated, a laboratory study was designed and a phase behavior computer model developed. The laboratory work focused on the effects of nitrogen gas cycling on the composition of the crude oil. Specifically the extent to which the oil is being vaporized by the injected nitrogen was to be examined. The physical properties of the crude oil, such as the viscosity and density, were monitored for changes.

The phase behavior model was developed to model the results obtained from the PVT cell, and the parameters controlling its performance tuned from the laboratory data obtained. The results obtained from the model were then used to quantify the amount of oil being vaporized by the injected nitrogen as the number of injection-withdrawal cycles increases. The model could then be used for vapor-liquid flash calculations.

From the perspective of the field setting, the focus of the study is the determination of nitrogen required for injection, the extent to which the crude oil is being contacted by the injected gas and most importantly, the crude oil shrinkage factor being observed after repetitive cycles of nitrogen injection and crude oil production. The work plan called for the use of data obtained from a field area where nitrogen injection had been ongoing for 4 years.

Another objective of this investigation is to identify the mechanisms attendant to the nitrogen huff and puff process and to use them to develop a screening guide for operators considering application of the process. Ultimately, field work coupled with the laboratory study of the cyclic process, should facilitate the design of reservoir compositional models for the study of huff and puff processes in specific fields.

1.3 Field Background

The Big Sinking field in Eastern Kentucky lies on the Western flank of the Appalachian basin. The field has been producing since the early 1900's. The underlying reservoir is pressure depleted with a remaining pressure of about 50-psig. The net thickness of the reservoir is about 40-ft and the depth to the top of formation is approximately 1300-ft. The reservoir has a porosity of approximately 16-% and has a matrix permeability of approximately 19-md. The average water saturation of the reservoir is approximately 50%. The crude oil's gravity is 36° API.

The current area of interest is the Big Andy field, an extension of the Big Sinking Field located on its Southeastern margin. The reservoir characteristics are similar since there are no discontinuities in the formation; however, the Big Andy reservoir is naturally fractured. Most of the wells had been drilled in the early 1980's with a total of some 400 active wells. In the mid 1980's a waterflood pilot test was initiated in the Big Andy with no success due to the reservoir's natural fracture. As such, by the late 1980's other alternatives were investigated. CO_2 huff and puff was used as an alternative to waterflooding. Following CO_2 injection, membrane generated nitrogen was introduced.

The nitrogen huff and puff was initiated in 1998. Using membrane technology, nitrogen is generated on site at an approximate cost of $ 1.00/MSCF. One advantage of using nitrogen is its immiscibility in water and oil. As a consequence, of its immiscibility, the injected nitrogen remains in the gas phase. Additionally, nitrogen is environmentally benign, non-corrosive and easily disposed of through venting to the atmosphere. The nitrogen huff and puff process is a new technique with no prior field application (US patent # 6,244,341).

As such, the design of a PVT experimental study, matched by production data from the Big Andy field will help in the development of screening criteria necessary for wider application of the technology within the United States. Once the experimental framework is developed, a phase behavior model can be used and the parameters of the EOS tuned to fit the laboratory results. Ultimately, as the process becomes better understood, independent producers will have the capability to consider its application to other reservoirs.

1.4 Project Description

A PVT cell system was fabricated for the purpose of conducting the cyclic injection-withdrawal experiment using nitrogen and oxygen. The cell is manufactured by Temco™ and has an internal volume of 500 cc. In addition, the cell uses a hydraulic piston to vary the volume of the cell. Along with the PVT cell, an air bath has been installed surrounding the PVT cell, in order to vary the temperature of the cell. The current achievable temperature range is 65ºF to 100ºF.

Before using the cell it was necessary to validate the accuracy of the apparatus. Several tests were conducted using single as well as two and three-component systems. The results obtained were then compared with the results available in literature. For instance, a plot of pressure versus specific volume was constructed and compared to available data for the case of pure propane.

Also mixtures of propane-ethane and propane-methane were used to generate similar pressure-volume plots.

Testing was done to analyze the effects of bubbling nitrogen at a constant flow rate through a crude oil sample. Samples of gas were collected and the composition determined using a Gas Chromatograph (GC) unit. The observed trend was a decrease in composition of the lighter components of the crude, with time. The next step was to collect the liquid samples from the PVT cell which had been subjected to the nitrogen treatment. These samples were then analyzed for composition and determination of physical properties.

In conjunction with the experimental laboratory work, well head gas samples were taken and analyzed from several wells in the Big Andy field. The purpose of this was to initiate a study at the field scale of the impact of the repeated injection/withdrawal cycles of nitrogen on in situ crude oil.

EXPERIMENTAL

2.1 Experimental Apparatus

A PVT window cell was fabricated using a Temco™ (Serial # 2503) piston cylinder. The stainless steel cylinder has an internal volume of 500 cubic centimeters (cc) when the piston is fully retracted (see Figure **3.1**). The maximum allowable working pressure is 5,000 psig, with a test pressure of 7,500 psig. The maximum allowable temperature is 350 º F. The piston cylinder is mercury free. The cell is mounted on two legs which allow it to move to an upward and downward position (for rocking purposes). This permits mixing and ensures equilibrium (for flash calculations) between the gas and liquid phases once fluids are injected into the cell. The cell contains a window at the front end which allows the fluids to become visible, hence facilitating measurements of liquid and/or vapor volumetric fractions. Figure **2.2** shows a picture of the PVT cell connected with the necessary equipment for conducting the experimental work. These include:

1. A linear variable differential transformer (LVDT) designed by Macro Sensors (model PR 812 – 4000).
2. Two OMEGA™ pressure transducers (PX 203-1KG5V) attached to the PVT cell.
3. A manual hydraulic pump (Enerpac PH 39) connected to the cell for piston displacement (see Figure **2.3**)
4. Two mass flowmeters (Omega FMA 1706) permit independent measurements of the flows of nitrogen and oxygen independently from the gas cylinders to the PVT cell.
5. A computerized data acquisition instrument, LabView™ which enables monitoring of pressure, temperature, volume and flow rates of injected gas into the cell.
6. A thermocouple to monitor temperature variations within the cell.
7. A Gas Chromatograph for analysis of the collected vapor samples (see Figure **2.4**)
8. A Brookfield viscometer for fluid viscosity measurement (see Figure **2.5**)

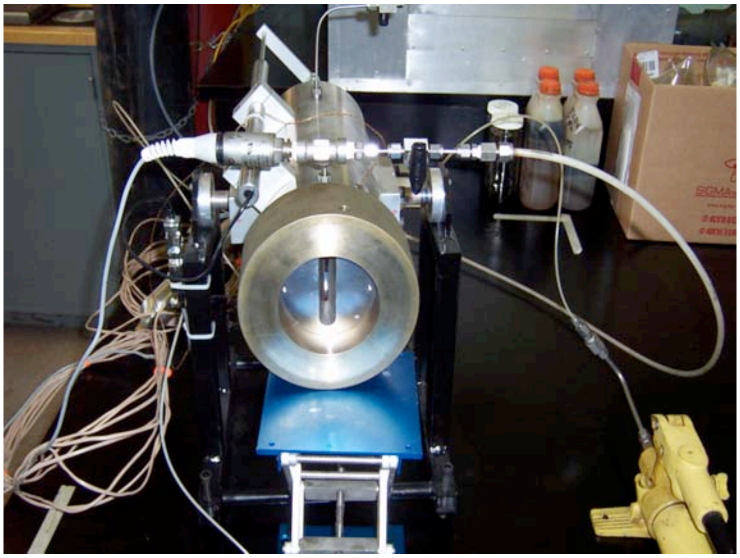


Figure **2.1**: Temco PVT Cell

Figure **2.2**: Complete Lab Set-up

Figure **2.3**: Enerpac Hydraulic Pump

Figure **2.4**: Shimadzu G.C. 17A

Figure **2.5**: Brookfield Viscometer

The gas chromatograph shown on Figure **2.4** is a Shimadzu brand, model G.C. 17A. The unit contains two detectors for analyzing different compounds. The first, an FID detector, is capable of detecting hydrocarbon compounds ranging from methane up to C_{20}. The second is a TCD column capable of detecting nitrogen, oxygen and carbon dioxide. Together, both detectors are used to determine the composition of the gas collected from the PVT cell.

In addition to the G.C. unit, a Brookfield viscometer is used to measure the viscosity of the crude oil sample before and after the injection process. The viscometer contains a circular plate where the liquid is placed, and a rotating shaft to measure the torque of the shaft against the fluid. The concept is to rotate the shaft at a certain known velocity which is translated into a torque. The torque is a measure of the resistance of the fluid on the shaft. This torque measurement is then used to compute the viscosity.

2.2 Experimental Procedure

The objective of the experimental procedure was to inject nitrogen into the PVT cell containing crude oil, permit mixing of the N_2 with the oil sample, remove the vapor from the cell, and analyze it using a gas chromatograph (G.C.) instrument. Further, a period of 24-hours was used to permit the injected gas to reach equilibrium with the crude oil. It is worth noting that this time frame was chosen randomly and was not optimized during the experimental work. Following this 24-hour period, a sample of the vapor was withdrawn and analyzed to determine its composition. The following procedure was used to obtain the necessary data:

1. A sample of crude oil is selected from a well not previously treated with nitrogen. A volume of 400 cubic centimeters (cc) is chosen to facilitate the determination of vaporization. Mass and density are also measured for the sample to be analyzed. The oil sample is injected into the PVT cell at atmospheric conditions and the cell is sealed. Air is purged from the cell using nitrogen.
2. The piston is then pushed forward with the manual pump until the cell is completely filled with the oil (single phase) prior to injection.
3. A 500-cc cylinder is pressured up to 200-psig using nitrogen gas. The nitrogen gas is either 100 percent by molar composition or mixed with oxygen (up to 14 percent by volume) depending on the experiment. Table **2.1** contains the test matrix developed for varying the nitrogen-oxygen mixture injected into the PVT cell.
4. The nitrogen gas is then injected into the PVT cell until a pressure of 150-psig is reached. The 150-psig was selected to mimic field conditions. As mentioned previously, the cell is initially at atmospheric conditions.
5. The final step consists of allowing the fluids to reach thermodynamic equilibrium by permitting the crude oil and nitrogen to reside for 24 hours in the cell. Periodic rocking of the cell was used to promote mixing and the attainment of thermodynamic equilibrium.

6. A sample of vapor is then removed from the PVT cell and collected in a Teddlar bag designed for gas sample collection. The remaining vapor is vented from the cell, allowing only the liquid to remain in the cell. The PVT cell is then returned to its initial pre-injection conditions by moving the piston until only the remaining liquid can be seen through the window.
7. The Teddlar bag containing the vapor is then taken to the G.C. laboratory for analysis. Two samples of 300 micro liters (μL) are extracted using a 1 liter syringe. The first sample is injected into the FID column to analyze the composition of the hydrocarbons. The second sample is injected into the TCD column to determine the composition of nitrogen, oxygen and carbon dioxide.
8. The remaining vapor is vented from the cell, keeping only the liquid in the cell. The PVT cell is then returned to its initial pre-injection conditions by moving forward the piston until only the remaining liquid can be seen through the window.
9. Another cycle of gas is then prepared for injection and the process is repeated. Six cycles are performed using the PVT cell.
10. The crude oil's viscosity following the injection-withdrawal cycles was determined using the Brookfield viscometer

Table **2.1**: Nitrogen-Oxygen Test Matrix

Injection Gas / Oil Sample	N_2 (100) %	N_2-O_2 (97-3) %	N_2-O_2 (86-14) %
19P * (no prior N_2 injection)	6 Cycles	6 Cycles	6 Cycles
Pressure,Temp	150(psig), 70(°F)	150(psig),70(°F)	150(psig), 70(°F)

* Well 19P is located on the James Booth lease

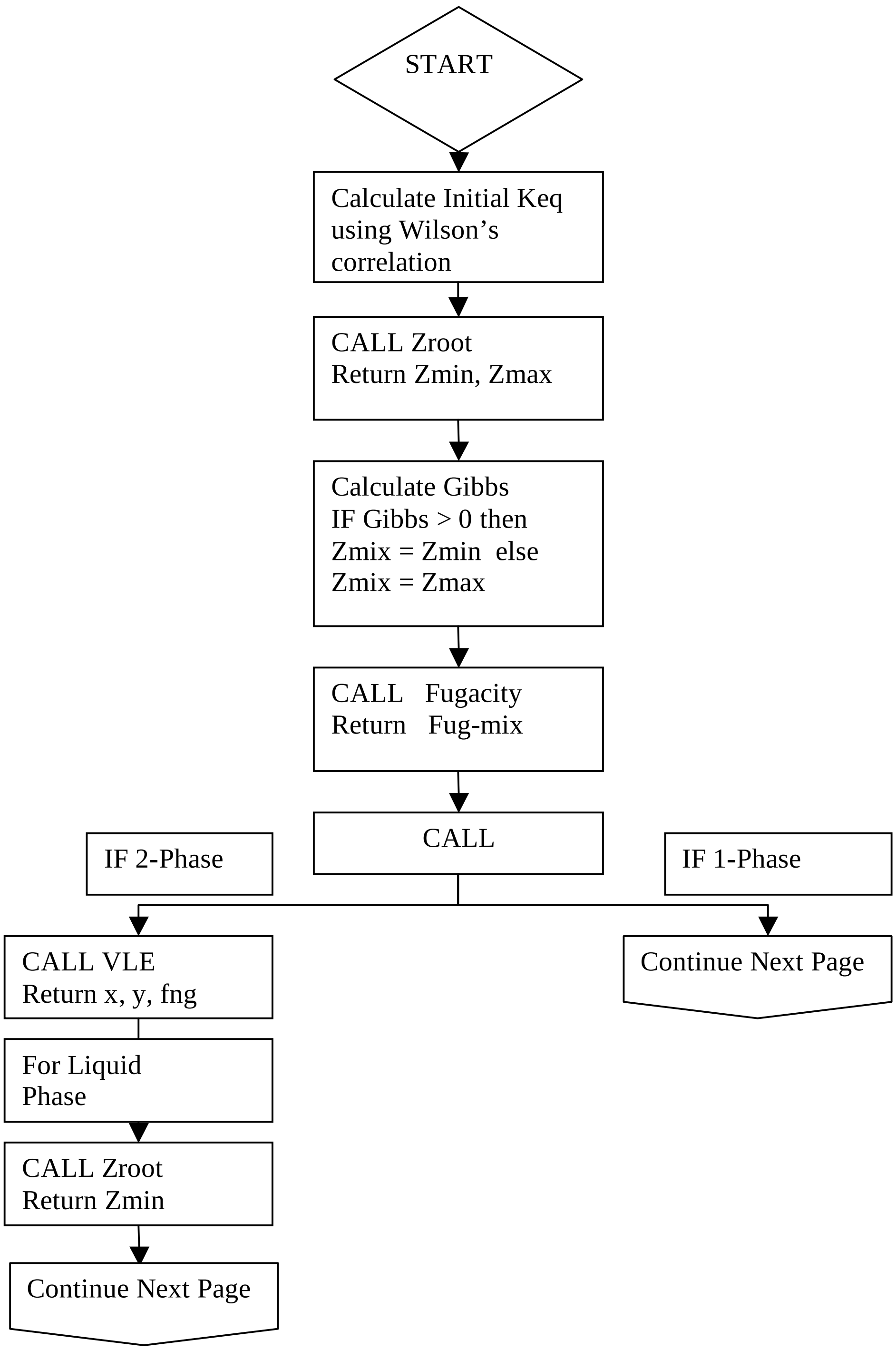
PHASE BEHAVIOR MODEL

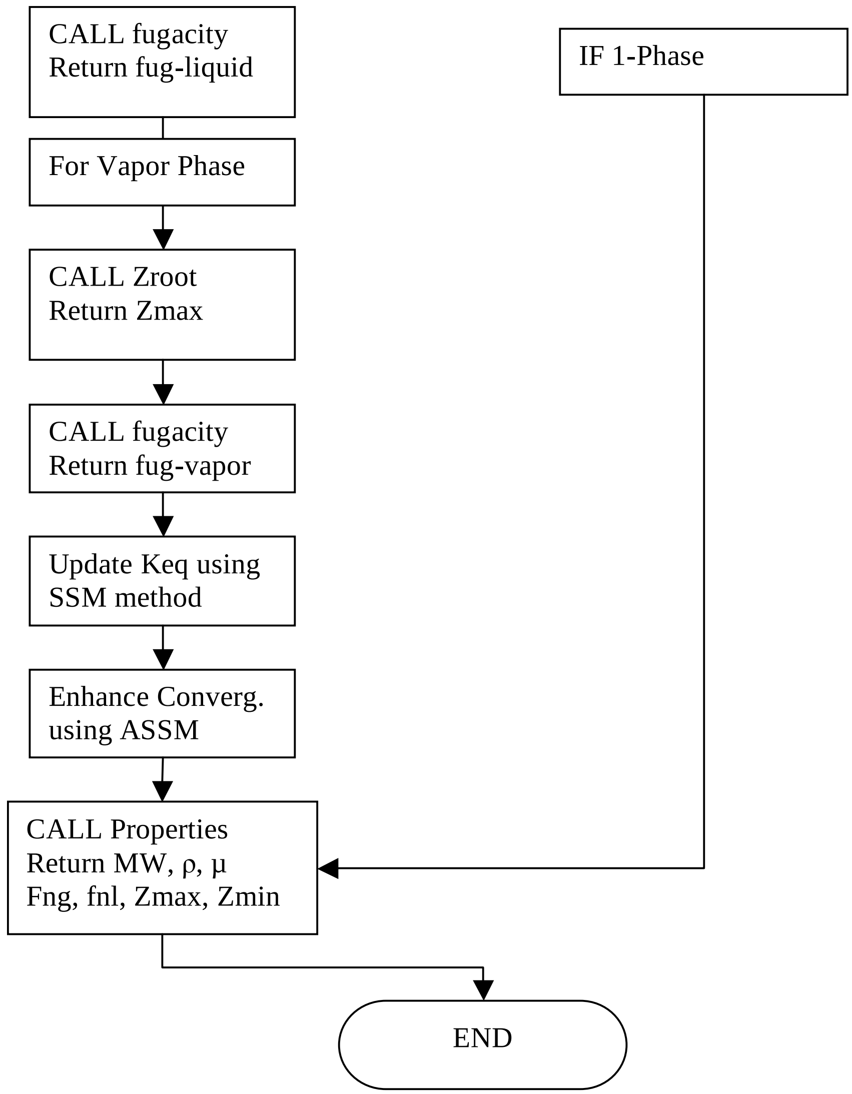
3.1 Objective and Problem Statement

Phase behavior prediction has always played an integral role in reservoir engineering. It is also important for production engineers concerned with the design of such things as pipelines and surface production facilities.

The purpose of this section is to familiarize the reader with the phase behavior model and the process by which it is used in conjunction with the experimental work. The phase behavior model discussed here is a set of algorithms written in FORTRAN® (formula translator) language in order to perform vapor liquid equilibrium (VLE) flash calculations - Figure **3.1** shows a flow chart of the overall algorithm. Realizing successful implementation, we can then determine whether a given composition will exist as a single phase or more, and the physical properties that characterize its behavior. The model will also permit a calculation of the change in composition as nitrogen is being cyclically injected, and equilibrium is realized during the "soaking" phase.

Figure **3.1**: Phase Behavior Model Flowchart




CALL fugacity
Return fug-liquid
For Vapor Phase
CALL Zroot
Return Zmax
CALL fugacity
Return fug-vapor
Update Keq using
SSM method
Enhance Converg.
using ASSM
CALL Properties
Return MW, ρ, μ
Fng, fnl, Zmax, Zmin
IF 1-Phase
END

3.2 Description of Modules

A comprehensive phase behavior model was developed to compute the properties of the gas and liquid phases. These properties include the densities, viscosities and molecular weights. The model was developed using several interdependent modules that are described in the following sections. The following sections discuss the procedures employed by each module. A more detailed technical description of each module can be found in Appendix B.

- **Phase Stability Test**

In order to determine whether a hydrocarbon mixture will exist as a single-phase or as two phases, a “detection routine” was performed. This first module was formulated for the purpose of determining the mixture’s phase.

In this module, the phase stability criterion proposed by Michelsen in 1982 was used [Michelsen, 1982]. The concept behind the stability test is the introduction of a “second-phase” inside the existing mixture. The stability test is then performed for two cases; a vapor-like “second-phase” and a liquid-like “second-phase”. A requirement for successful testing is that the compressibility factor of the mixture must be chosen such that it minimizes the Gibbs free energy. When the test is performed, the outcome is either a single phase system or a two phase system. In the case where two phases are present, VLE calculations are initiated to determine the molar fractions of both the vapor and liquid.

- **Vapor Liquid Equilibrium Calculation (VLE)**

The VLE subroutine is used to determine whether the mixture will remain as a single phase or split into a two phase system. If two phases are present, the molar quantities of both vapor and liquid are determined. In order to do so, the Rachford-Rice Objective function (see Equation 1) was used to compute the equilibrium constant (K_i), which is the ratio of vapor molar fraction to that of liquid ($K_i = Y_i/X_i$) [Rachford and Rice, 1952].

In order to do so, Wilson’s empirical correlation (Equation 2) is used to calculate a first estimate of the equilibrium constants. The equilibrium constants are later updated through the use of a more robust method, one which requires more rigorous thermodynamic principles.

$$g\left(f_{ng}\right)=\sum_{i=1}^{n_c}\frac{c_i\left(k_i-1\right)}{1+f_{ng}\left(k_i-1\right)} \tag{1}$$

$$k_i=\frac{1}{P_{ri}}e^{\left[5.37\left(1+w_i\right)\left(1-\frac{1}{T_{ri}}\right)\right]} \tag{2}$$

- **Compressibility Factor Prediction (Z-root)**

In order to predict the volumetric behavior of a hydrocarbon multi-component system, an equation of state (EOS) that describes the system is required. For this study, the Peng-Robinson Equation of State (PR-EOS) was chosen [Peng and Robinson, 1976]. The PR-EOS has the form:

$$P=\left(\frac{R\times T}{V_m-b_m}\right)-\left(\frac{\left(a\times\alpha\right)_m}{V_m^2+2b_mV_m-b_m}\right) \tag{3}$$

In cubic form in term of the compressibility (Z):

$$Z^3+a_1Z^2+b_1Z+c_1=0 \tag{4}$$

where:

$$a_1=-\left(1-B\right))$$
$$b_1=A-3B^2-2B$$
$$c_1=-\left(AB-B^2-B^3\right)$$

$$A = \frac{(a\alpha)_m P}{R^2 T^2} \qquad (5)$$

$$B = \frac{b_m P}{RT}$$

The task is to solve expression (4) for the compressibility factor of the hydrocarbon mixtures and then to move on to vapor liquid equilibrium calculation (VLE). The Peng and Robinson equation of state (EOS), Equation (3), was selected because it is widely used in the petroleum industry and most importantly, it is more reliable when applied to a wide range of hydrocarbon systems. In order to solve the cubic Equation (4), a numerical method is required. The Newton Rhapson technique is used for non-linear systems and can provide reliable results. It will be used to solve for the compressibility factor.

- **IsoFugacity Criteria and SSM (successive acceleration method)**

In the previous subroutine (VLE), an empirical method (Wilson's correlation) was used to calculate the equilibrium constant (K_i) of the composition. However, the values obtained were only estimates and did not represent an accurate thermodynamic evaluation. The fugacity will prove to be more accurate through the use of more rigorous thermodynamic equilibrium considerations. Thermodynamic equilibrium is achieved when all net transfer (heat, momentum, mass) is zero. Hence the potential must be the same under such conditions which in turn requires the fugacities (see Equation 6) of all components to be the same. Equation (6) is then related to the equilibrium constants through equation (7). When the fugacities of the components are obtained, they can then be updated using Wilson's initial prediction, through the SSM technique (8).

$$f_{li} = f_{gi} \text{, for all i's} \qquad (6)$$

where:

f_{li} = fugacity of the i-th component in liquid phase

f_{gi} = fugacity of the i-th component in the vapor phase

$$K_i = \frac{\phi_{li}}{\phi_{gi}} = \frac{f_{li}/(x_i P)}{f_{gi}/(y_i P)} = \frac{y_i}{x_i}\left(\frac{f_{li}}{f_{gi}}\right) \qquad (7)$$

and,

$$K_i^{n+1} = K_i^n \left\{\frac{f_{li}}{f_{gi}}\right\}^n \qquad (8)$$

- **ASSM (Accelerated Successive Substitution Method)**

The SSM technique that was used previously to increase the convergence rate is more robust in predicting K-values than Wilson's method. However, it is slow to converge around critical points and another technique, which can be implemented at or near critical conditions, is required.

The SSM generates the first equilibrium-constant values, and a switching criterion is checked in order to implement the ASSM. If all the criteria are met, the SSM switches to the ASSM and updates the equilibrium values. The ASSM is then tested to determine if the solution is improving (fugacities are close to unity). If the ASSM does not generate improved solutions, its use is discontinued and the routine, switched back to the SSM without returning to it.

- **Property Prediction**

The final module computes the density, viscosity and molecular weights of the liquid and vapor compositions. These properties can be readily obtained since we have generated in the previous modules all the necessary tools. The molecular weights as shown in Equation (9) are generated using the molar fractions (liquid and vapor) that were calculated. From these, the densities are computed by implementing Equation (10).

$$MW_g = \sum_{i=1}^{n} y_i MW_i \qquad (9)$$

$$MW_l = \sum_{i=1}^{n} x_i MW_i$$

$$\rho_a = \frac{P}{RT}\left(\frac{MW_a}{Z_a}\right) \qquad (10)$$

The next step is to compute the viscosities of the phases. For determination of the gas viscosity, the Lee-Gonzalez-Eakin (1966) method was used. This predictive method is presented in Equation (11).

$$\mu_g = 1.10^{-4} k_v EXP\left(x_v \left(\frac{\rho_g}{62.4}\right)^{y_v} \right) \text{ (cp)} \qquad (11)$$

where:

$$k_v = \frac{(9.4 + 0.02MW_g)T^{1.5}}{209 + 19MW_g + T}$$

$$y_v = 2.4 - 0.2x_v$$

$$x_v = 3.5 + \frac{986}{T} + 0.01MW_g$$

For determination of the liquid phase viscosity, Lohrenz, Bray and Clark correlation (1964) was used:

$$\mu_l = \mu^* + \xi_m^{-1}\left[\left(0.1023 + 0.023364\rho_r + 0.058533\rho_r^2 - 0.040758\rho_r^3 + 0.0093724\rho_r^4\right)^4 - 1.10^{-4} \right]$$

where:

$$\rho_r = \frac{\rho_l}{\rho_{pc}} = \left(\frac{\rho_l}{MW_l}\right)V_{pc}$$, reduced density of the liquid mixture

$\xi_m = \frac{5.4402 T_{pc}^{1/6}}{\sqrt{MW_l}\, P_{pc}^{2/3}}$ mixture viscosity parameter

u^* viscosity at atmospheric conditions, cp

T_{pc} pseudocritical temperature, °R

P_{pc} pseudocritical pressure, psia

RESULTS AND DISCUSSION

4.1 Field Work Analysis

The ongoing field operations of Bretagne GP in Eastern Kentucky provide the real– world basis for the experimental work that was performed at the Pennsylvania State University. As previously noted, nitrogen, is being injected into the Big Andy Field. Liquid production from the field has increased from 100 STBD to approximately 500 STBD using the nitrogen huff and puff technique. Based on these results and the analysis of gas collected from several wells in the field, it is recognized that there are at least two processes in play at the field level. The first is displacement where the nitrogen expands resulting in the flow of oil into the wellbore. The second process is the interphase mass transfer of the lighter components[1] from the liquid phase to the gas phase. Although the stripping process might not be desirable, a better understanding of its occurrence in the reservoir could help operators determine the ultimate recovery and number of cycles which can be performed on the field. While it is this second process which is being investigated in this work, it is worth noting that the field's production has increased as a result of the nitrogen huff and puff injection.

The process employed in the field amounts to the injection of approximately 1000 MSCF/Well of nitrogen-oxygen mixture. The well is then shut-in for approximately 30 days to permit soaking of the nitrogen with the oil and to permit percolation of this gas toward the top of the reservoir. For the field portion of this project, the James Booth lease was selected because the wells contained on this lease have little interference with wells located on adjoining leases. This minimizes the loss of injection gas to competing drainage patterns.

In this study the focus is the mass transfer realized between the injected nitrogen and the crude oil resident in the reservoir. To this end, gas samples were collected from the several wells

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[1] For the purpose of this study light components refer to methane through butane. Intermediate components refer to pentane through nonane, and heavy components, decane plus.

located on the Booth lease. These samples were collected and analyzed at the Pennsylvania State University using a gas chromatograph unit.

Figure **4.1** contain the results of the gas samples composition of the vapor phase taken from the wells after the soaking period and the production has been resumed. This plots show a significant amount of light hydrocarbons that have been transferred from the crude oil to the gas phase. It is this phenomenon that is the basis for the experimental work that was undertaken. Moreover, it is the impact of this vaporization on physical properties such as density and viscosity that was to be investigated.

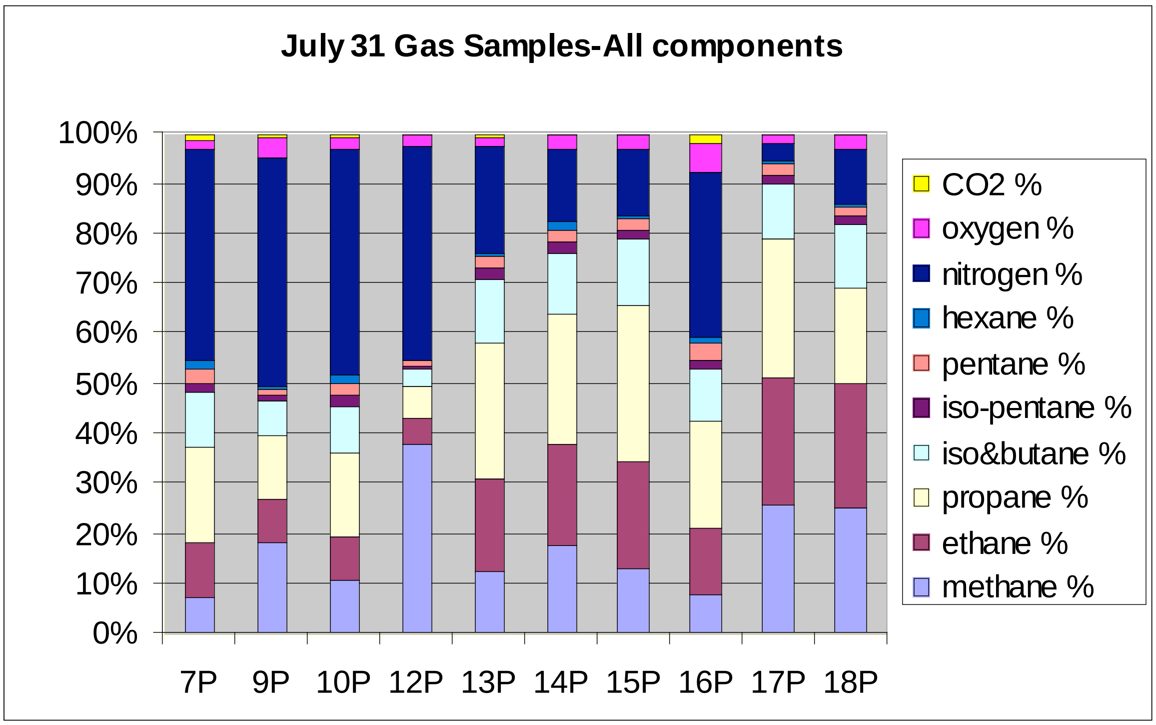

Figure **4.1**: G.C. Analysis J.B. Lease July 04

4.2 <u>Laboratory Data Analysis</u>

5 gallons of crude oil with no prior contact to nitrogen cyclic injection was obtained from well 19P in the James Booth lease (Figure **4.2**) located in the Big Andy field, Eastern Kentucky.

The liquid sample was sent for analysis to Questar Applied Technology. The results obtained (Table **4.1**) were then used as a starting reference for the experimental as well as modeling work to be performed later. The composition obtained shows that the crude oil is very light with an API gravity of 68.9. The specific gravity of the crude oil is 0.705 (density of water 1gm/ml) and the average molecular weight is 104.4 grams/mole.

A predetermined mixture of nitrogen-oxygen was injected into the crude oil. For the first test, pure nitrogen (100% molar fraction) was injected into the cell. The cell was brought to a pressure of 150 psig to be consistent with the average injection pressure realized during field operations. The temperature was also kept at 70°F. These parameters are maintained throughout the entire experimental study. The mixture of injected gas and crude oil was allowed to soak for 24 hours to ensure equilibrium before collecting a sample of vapor for analysis. The second series of tests were conducted using a 97-3 % N_2-O_2 mixture. The last series of tests were conducted using 86-14 % N_2-O_2 mixture. The soaking time was similar to that using 100 % N_2. Varying the composition of the injected gas would help identify any changes brought by the addition of oxygen to the injection process. While the vapor from the PVT cell was collected and analyzed with a gas chromatograph unit, the liquid was sent to Questar Applied Technology for analysis. The vapor from the PVT cell was collected in a 1 liter Teddlar bag. A volume of 300 micro liters (μL) was injected into the G.C. unit as required for detection of the desired hydrocarbons. The G.C. unit produces the appropriate peaks for each hydrocarbon component, which are then converted to a molar fraction. The remaining liquid in the PVT cell is kept in place and used for the subsequent injection cycle. The cell is also purged of any remaining vapor by moving the piston on the cell until the only phase that can be viewed by the operator through the window port is the liquid phase.

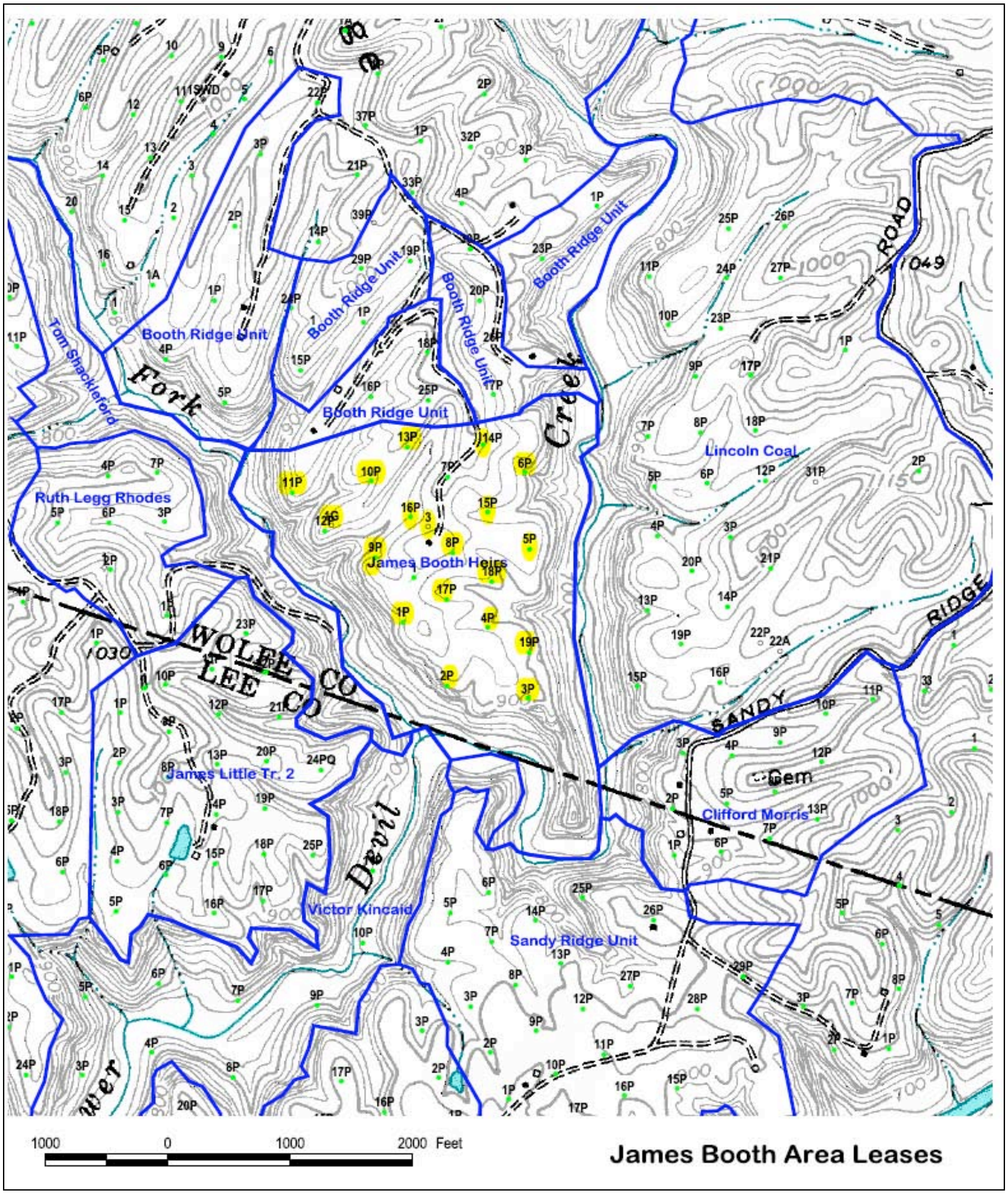

Figure **4.2**: Big Andy Field, Kentucky.

Table **4.1**: Sample 19P Composition Analysis (Pre-Injection)

Component	Mol%	Wt%	LV%
Methane	0.1725	0.0265	0.0624
Ethane	1.1076	0.3190	0.6335
Propane	5.4762	2.3127	3.2205
Isobutane	1.2196	0.6789	0.8515
n-Butane	7.5039	4.1772	5.0493
Neopentane	0.0107	0.0074	0.0087
Isopentane	3.6941	2.5525	2.8857
n-Pentane	6.8089	4.7047	5.2630
2,2-Dimethylbutane	0.0557	0.0460	0.0496
2,3-Dimethylbutane	0.8072	0.6662	0.7058
2-Methylpentane	2.7283	2.2517	2.4162
3-Methylpentane	1.6715	1.3795	1.4555
n-Hexane	5.8494	4.8275	5.1320
Heptanes	21.8014	20.1219	19.3788
Octanes	11.1952	11.9497	11.5999
Nonanes	8.8744	10.3474	9.6748
Decanes plus	20.9585	33.6139	31.5974
Nitrogen	0.0633	0.0170	0.0148
Carbon Dioxide	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000
Global Properties		**Units**	
Avg Molecular Weight	104.4210	gm/mole	
Pseudocritical Pressure	430.24	psia	
Pseudocritical Temperature	510.57	degF	
Specific Gravity	0.70598	gm/ml	Light Comp.
Liquid Density	5.8857	lb/gal	9.8172 %
Liquid Density	247.20	lb/bbl	
Specific Gravity	2.8158	air=1	Inter. Comp.
SCF/bbl	900.95	SCF/bbl	58.57 %
SCF/gal	21.4513	SCF/gal	
MCF/gal	0.0215	MCF/gal	Heavy Comp
gal/MCF	46.638	gal/MCF	31.597 %
Net Heating Value	4293.5	BTU/SCF at 60°F	
Net Heating Value	15511.8	BTU/lb at 60°F	
Gross Heating Value	4642.9	BTU/SCF at 60°F	
Gross Heating Value	16712.6	BTU/lb at 60°F	
Gross Heating Value	97784.3	BTU/gal at 60°F	
API Gravity	68.9		

The results using injection gas that is 100 % N_2 were obtained from the G.C. analysis of the produced vapor phase. The analysis on Figure **4.3** illustrates the components of the hydrocarbons being vaporized by the injected gas. Also, Figure **4.4** indicates that the after 6 injection cycles, the total produced vapor is composed of approximately 5 % hydrocarbons. These results also indicate that the lighter components of the hydrocarbons in the crude oil are being vaporized along with the intermediate components. The lighter components constitute approximately 60 % of the total hydrocarbons being stripped (3 % molar fraction). Mass transfer of these components occurs during the soaking period when equilibrium between the injected N_2 and the crude oil is achieved. The results also indicate that the quantity of the lighter component being stripped by the gas decreases gradually with every injection cycle as can be seen on Figure **4.4**. This means that there are less of the light ends in the crude oil after repetitive injection cycles. The trend also shows that the lighter components of the crude oil are more readily stripped than the heavier and intermediate ones. This is the result of the lighter component having higher vapor pressures than the heavier components and resulting in easier striping. The more volatile a gas is, the higher its vapor pressure. Hence the lighter, more volatile components will have less cohesive forces than the heavier components. This is also consistent with the observations made in the Big Andy Field.

Complementary to the results obtained from the G.C. unit, the liquid sample which was sent to Questar Applied Technology for analysis has also shown interesting trends. The results obtained (see Table **4.2**) have shown that after 6 cycles of 100 % nitrogen injection the molecular weight of the crude oil increases from 104.42 g/mole to114.07 g/mole. Also, the density increases from 5.88 lb/gal to 6.00 lb/gal and the API gravity decreased from 68.9 to 64.9 after 6 cycles. Most importantly, the crude oil’s shrinkage was calculated given the data obtained and found to be around 6 % by volume for the case of 100 % N_2 injection (see Table **4.3**). When calculating the shrinkage for the injection cycles of 97-3 % N_2-O_2, and 86-14 % N_2-O_2 the numbers were slightly lower, and the shrinkage was found to be approximately 4 % by volume. The shrinkage by mass was also calculated for the three different injection cycles and found to be approximately 4 % for the case of 100 % N_2 injection and 2 % for the other two injections. The results obtained indicate that the 100 % N_2 injection has caused more shrinkage, both by mass and by volume, than the 97-3 % N_2-O_2 and the 86-14 N_2-O_2. This could be caused by experimental error during analysis of the sample. Further work is needed to determine the role of oxygen in the stripping process.

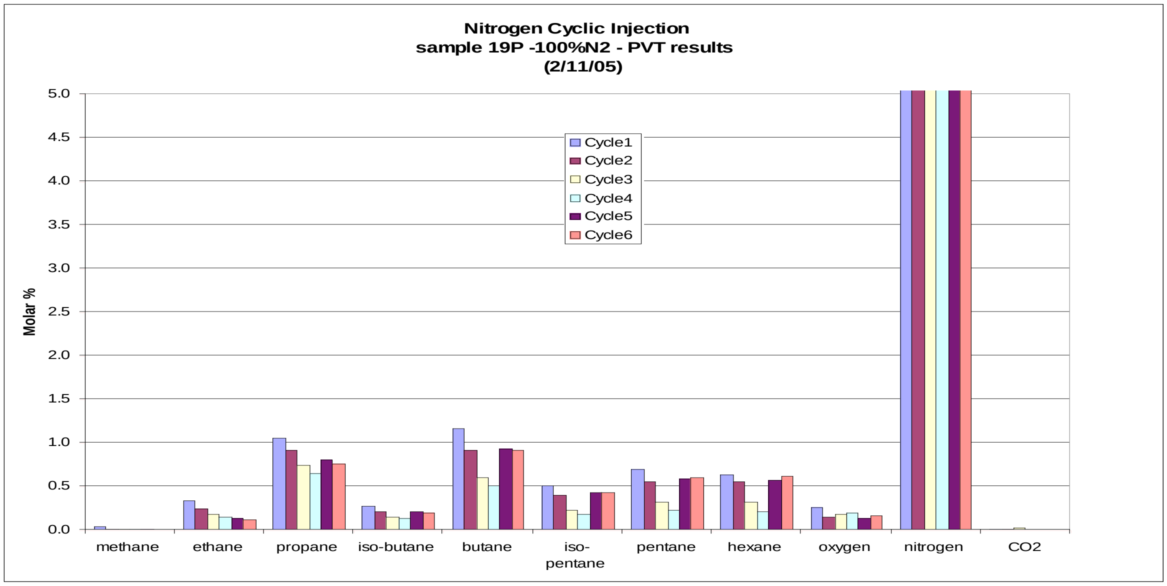

Figure **4.3**: G.C. Results Sample 19P-100%N_2

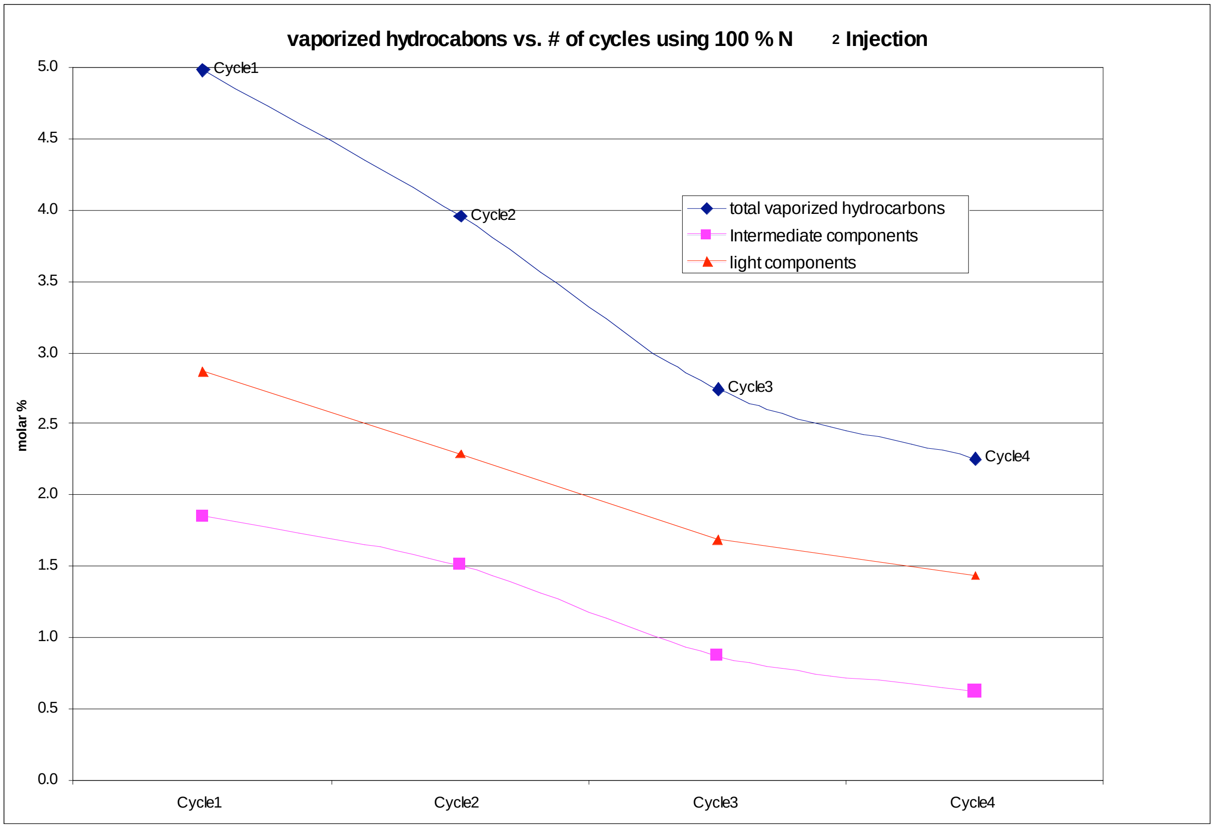

Figure **4.4**: Vaporized Hydrocarbons using 100 % N_2

Table **4.2**: Sample 19P – 100 % N_2 (Post Injection)

Component	Mol%	Wt%	LV%
Methane	0.0432	0.0061	0.0146
Ethane	0.0000	0.0000	0.0000
Propane	1.3981	0.5405	0.7682
Isobutane	0.6413	0.3267	0.4183
n-Butane	4.7840	2.4375	3.0076
Neopentane	0.0000	0.0000	0.0000
Isopentane	3.0418	1.9239	2.2202
n-Pentane	5.9442	3.7596	4.2930
2,2-Dimethylbutane	0.0540	0.0408	0.0450
2,3-Dimethylbutane	0.8838	0.6677	0.7221
2-Methylpentane	2.6412	1.9953	2.1854
3-Methylpentane	1.6988	1.2834	1.3821
n-Hexane	5.9487	4.4939	4.8766
Heptanes	23.6467	20.0148	19.6866
Octanes	12.2888	12.0432	11.9607
Nonanes	10.0812	10.8518	10.4372
Decanes plus	26.8184	39.5948	37.9635
Nitrogen	0.0852	0.0209	0.0186
Carbon Dioxide	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000
Global Properties		**Units**	
Avg Molecular Weight	114.0749	gm/mole	
Pseudocritical Pressure	403.12	psia	
Pseudocritical Temperature	551.64	degF	
Specific Gravity	0.72058	gm/ml	Light Comp.
Liquid Density	6.0074	lb/gal	4.2087 %
Liquid Density	252.31	lb/bbl	
Specific Gravity	2.9168	air=1	Inter. Comp.
SCF/bbl	842.07	SCF/bbl	57.808 %
SCF/gal	20.0492	SCF/gal	
MCF/gal	0.0200	MCF/gal	Heavy Comp
gal/MCF	49.907	gal/MCF	37.9635 %
Net Heating Value	4475.9	BTU/SCF at 60°F	
Net Heating Value	14805.0	BTU/lb at 60°F	
Gross Heating Value	4839.3	BTU/SCF at 60°F	
Gross Heating Value	15944.5	BTU/lb at 60°F	
Gross Heating Value	94856.5	BTU/gal at 60°F	
API Gravity	64.9		

Table **4.3**: Crude Oil Shrinkage

	100 % N_2	97-3 % N_2O_2	86-14 % N_2O_2
Mass shrinkage (%)	3.8	2.0	2.1
Volume shrinkage (%)	5.8	4.0	4.3

The results, using the second and last injection gases (97-3 % N_2-O_2 and 86-14 % N_2-O_2), were obtained from the G.C. analysis of the produced vapor phase. These were plotted on Figures **4.5** and **4.6**. The trend indicates that the composition of the vapor observed was not significantly different in comparison with the results obtained from the 100% N_2 injection. For instance the plots do not indicate any significant changes at the ethane and propane concentration (as well as other components) among the three injected gases. This would suggest that oxygen concentrations up to 14-% have little impact on the composition of the vapor after cyclic injection. The shrinkage difference could be the result of experimental error when collecting and analyzing the data.

The results obtained from the analysis of the liquid sample with the injection of 97-3 % N_2-O_2 and 86-14% N_2-O_2 are also presented in Tables **4.4** and **4.5** respectively. The results obtained were very similar to those with the 100 % N_2 injection. That is, there appears to be a similar trend with regards to the changes in physical properties before and after the injection process. For instance, the density increases from 5.88 lb/gal to 6.00 lb/gal with the injection of 97-3 % N_2-O_2 and 86-14 % N_2-O_2 respectively. The crude oil's average molecular weight increased from 104.42 gm/mol to 115.63 gm/mol.

The physical properties such as the viscosity and the density of crude oil samples from well19P were also measured in the laboratory before and after the injection process took place (see Table **4.6**). The initial viscosity (prior to any injection cycles) was measured and found to be 7.2 centipoise (cp). At the end of 6 injection cycles, the viscosity was measured again. The results indicated an increase from 7.2 cp to 9.0 cp in the case when the 97-3 % N_2-O_2 gas was injected. The viscosity also increased with the injection of the gas mixtures. These results indicate a shifting of the physical properties to a more viscous and higher density crude oil. It has also been observed that the color of the crude oil after 6 injection cycles darkens and loses its initial brownish color. No major changes have been observed with the addition of oxygen in the injection gas.

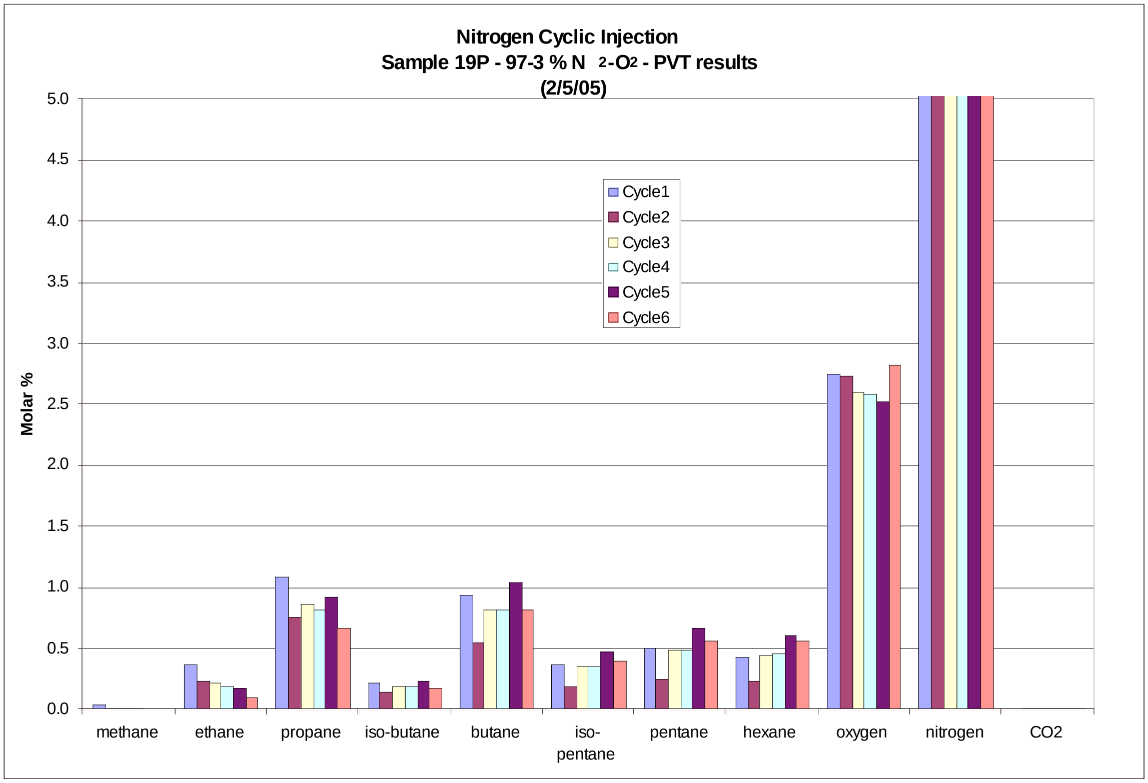

Figure **4.5**: G.C. Results Sample 19P – 97-3 % N_2O_2

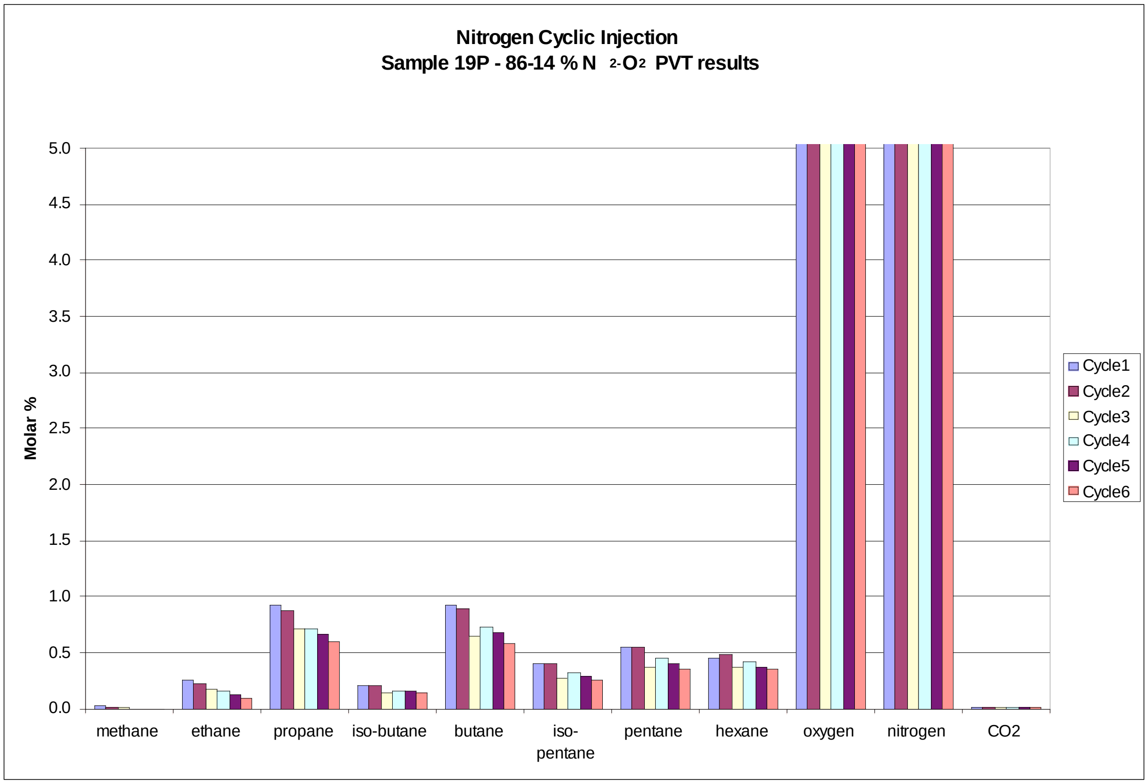

Figure **4.6**: G.C. results Sample 19P – 86-14 % N_2O_2

Table **4.4**: Sample 19P – 97-3 % N_2O_2 (post injection)

Component	Mol%	Wt%	LV%
Methane	0.0000	0.0000	0.0000
Ethane	0.0587	0.0154	0.0312
Propane	1.8697	0.7192	1.0223
Isobutane	0.6586	0.3339	0.4275
n-Butane	4.8849	2.4767	3.0560
Neopentane	0.0273	0.0172	0.0207
Isopentane	3.1034	1.9532	2.2540
n-Pentane	5.8983	3.7123	4.2390
2,2-Dimethylbutane	0.0500	0.0376	0.0414
2,3-Dimethylbutane	0.8388	0.6306	0.6820
2-Methylpentane	2.6150	1.9658	2.1532
3-Methylpentane	1.6975	1.2761	1.3743
n-Hexane	5.6683	4.2611	4.6239
Heptanes	22.6008	19.0347	18.7241
Octanes	11.6532	11.3596	11.2694
Nonanes	9.9459	10.6693	10.2760
Decanes plus	28.1286	41.4640	39.7389
Nitrogen	0.3013	0.0736	0.0655
Carbon Dioxide	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000
Global Properties		**Units**	
Avg Molecular Weight	114.6390	gm/mole	
Pseudocritical Pressure	401.71	psia	
Pseudocritical Temperature	550.84	degF	
Specific Gravity	0.72062	gm/ml	Light Comp
Liquid Density	6.0077	lb/gal	4.537 %
Liquid Density	252.33	lb/bbl	
Specific Gravity	2.8815	air=1	Inter. Comp.
SCF/bbl	837.91	SCF/bbl	55.65 %
SCF/gal	19.9503	SCF/gal	
MCF/gal	0.0200	MCF/gal	Heavy Comp
gal/MCF	50.157	gal/MCF	39.738 %
Net Heating Value	4402.5	BTU/SCF at 60°F	
Net Heating Value	14499.8	BTU/lb at 60°F	
Gross Heating Value	4764.4	BTU/SCF at 60°F	
Gross Heating Value	15616.8	BTU/lb at 60°F	
Gross Heating Value	92793.3	BTU/gal at 60°F	
API Gravity	64.9		

Table **4.5**: Sample 19P – 86-14 % N_2O_2 (post injection)

Component	Mol%	Wt%	LV%
Methane	0.0000	0.0000	0.0000
Ethane	0.0000	0.0000	0.0000
Propane	1.4614	0.5573	0.7939
Isobutane	0.5962	0.2997	0.3845
n-Butane	4.4831	2.2534	2.7865
Neopentane	0.0000	0.0000	0.0000
Isopentane	2.9454	1.8378	2.1255
n-Pentane	5.6814	3.5448	4.0568
2,2-Dimethylbutane	0.0523	0.0390	0.0430
2,3-Dimethylbutane	0.8568	0.6385	0.6921
2-Methylpentane	2.5504	1.9006	2.0864
3-Methylpentane	1.6442	1.2253	1.3225
n-Hexane	5.7745	4.3034	4.6802
Heptanes	23.1993	19.3753	19.1003
Octanes	12.0190	11.6116	11.5503
Nonanes	10.0413	10.6631	10.2797
Decanes plus	28.5371	41.7123	40.0654
Nitrogen	0.1579	0.0382	0.0341
Carbon Dioxide	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000
Global Properties		**Units**	
Avg Molecular Weight	115.6361	gm/mole	
Pseudocritical Pressure	399.36	psia	
Pseudocritical Temperature	556.36	degF	
Specific Gravity	0.72219	gm/ml	Light Comp
Liquid Density	6.0209	lb/gal	3.96 %
Liquid Density	252.88	lb/bbl	
Specific Gravity	2.9020	air=1	Inter. Comp.
SCF/bbl	832.49	SCF/bbl	55.936 %
SCF/gal	19.8212	SCF/gal	
MCF/gal	0.0198	MCF/gal	Heavy Comp
gal/MCF	50.480	gal/MCF	40.06 %
Net Heating Value	4407.7	BTU/SCF at 60°F	
Net Heating Value	14387.4	BTU/lb at 60°F	
Gross Heating Value	4768.3	BTU/SCF at 60°F	
Gross Heating Value	15494.1	BTU/lb at 60°F	
Gross Heating Value	92261.0	BTU/gal at 60°F	
API Gravity	64.4		

Table **4.6:** Physical properties after 6 injection cycles (PSU)

Sample 19P	100 % N2	97-3 N2-O2	86-14 N2-O2
initial viscosity	7.2 cp	7.2 cp	7.2 cp
final viscosity	7.8 cp	9.0 cp	8.3 cp
initial density	0.825 g/cc	0.825 g/cc	0.825 g/cc
final density	0.831 g/cc	0.834 g/cc	0.835 g/cc

4.3 Computer Model Data Analysis

The data obtained from the computer model were generated and compared with the data collected and analyzed from the PVT cell. Using the same initial composition shown in Table **4.2** and adding the required nitrogen-oxygen mixture, the new composition is then introduced to the computer model for phase splitting calculations. Once the pressure, temperature and overall composition are entered, the computer model generates new compositions of both the vapor and liquid phases along with their molar fractions and their physical properties. The result obtained from the liquid phase composition is then used to restart the splitting calculation for the next cycle with another batch of injection gas. The pressure and temperature used to simulate the laboratory data are kept constant at 150 psig and 70 °F. The amount of nitrogen injected is also kept constant. The initial results of the vapor composition were obtained using the initial interaction coefficients. These coefficients are then manipulated such that the results match as closely as possible those obtained from the laboratory model. The final coefficients are reported in Appendix C. A total of 8 cycles per injection mixture was used. This data can also be found in Appendix C.

The results obtained from the model were then plotted. Figure **4.7** shows the composition of the vapor phase that result from the phase splitting calculations after injecting the crude oil with

100% N_2. Figure **4.8** shows the composition of the liquid phase after injection. For the 97-3% N_2-O_2, Figures **4.9** and **4.10** were generated. Finally for the 86-14% N_2-O_2, Figures **4.11** and **4.12** were generated. In addition to these plots, shrinkage of mass as a function of the number of injection cycles were plotted for the 3 different injection mixtures. Figures **4.13, 4.14** and **4.15** contain these plots.

The most important observation was that the results obtained from the computer model have similar trends as those obtained from the laboratory analysis. These trends indicate a vaporization process which leaves the crude oil with less of its initial light components as the number of injection cycle increases. The number of cycles (8 for each gas mixture) did provide a good image of the change in composition as more nitrogen/oxygen is injected. The results obtained from Figures **4.7** to **4.12** also show that after 8 cycles a gradual decrease in vaporization is taking place. Hence the stripping effect seems to be diminishing. No significant changes have been observed when varying the composition of the injected nitrogen/oxygen mixture. This is also consistent with the data obtained from the PVT cell. It has also been found that the mass of the crude oil has decreased as a result of injection cycles. After 8 cycles, and for a given initial mass of oil, approximately 8.5% shrinkage on a mass basis was determined. This result is similar for all 3 injection mixtures with an insignificant difference among them. This shrinkage is important because it is consistent with observations obtained from the field and indicates that nitrogen injection causes vaporization and as a consequence shrinkage of reservoir fluid at the given conditions. It is also important because it allows further studies to focus on shrinkage in the crude oil caused by the nitrogen injection and to what extent the oxygen plays a role.

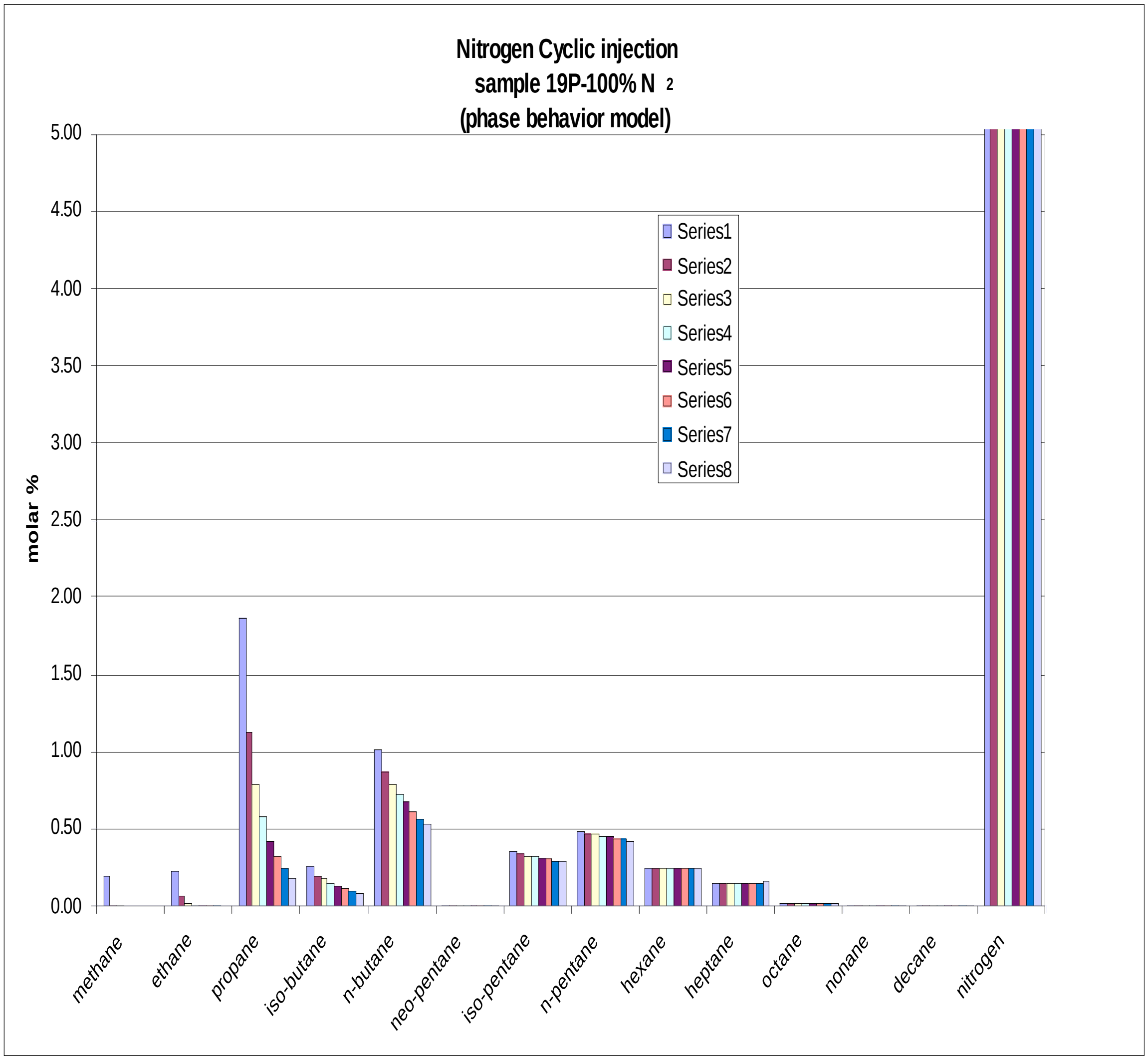

Figure **4.7**: Vapor Phase – Sample 19P – 100 % N_2

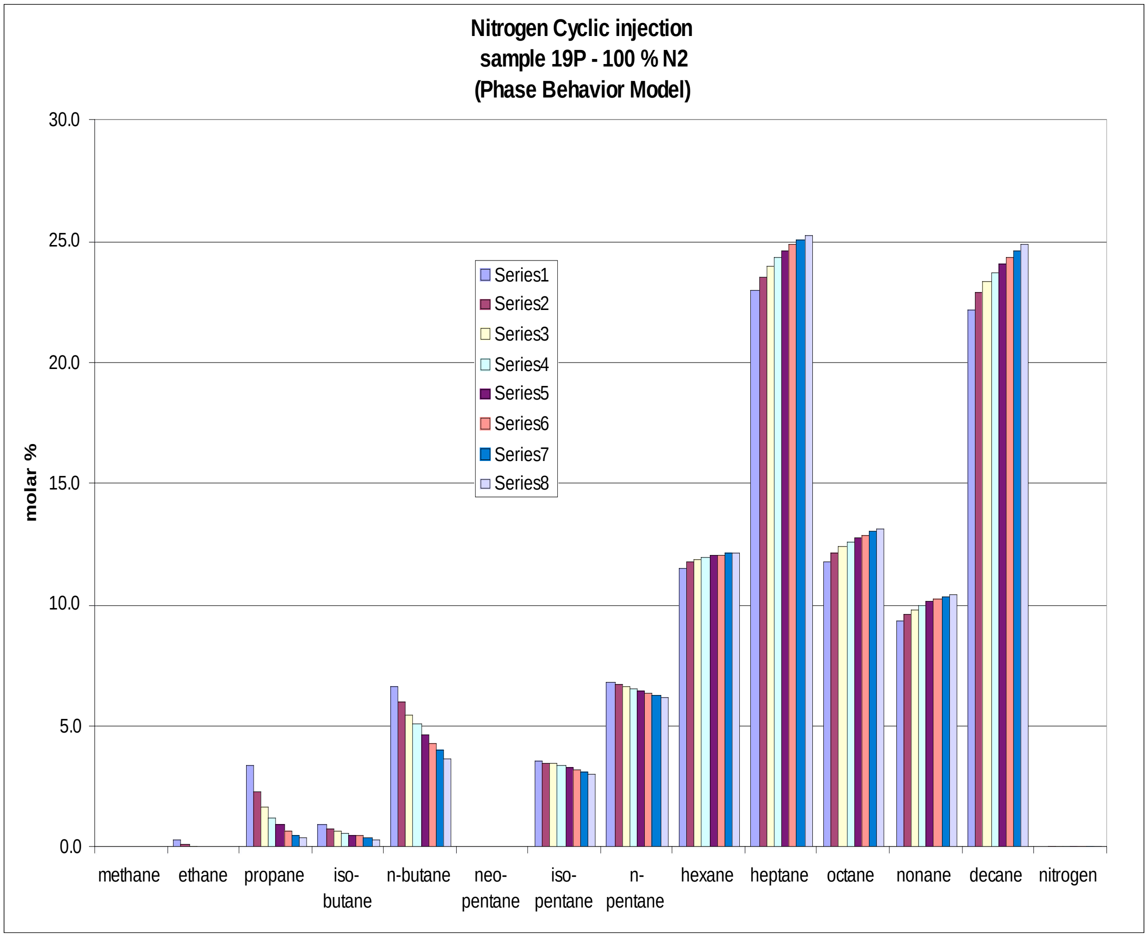

Figure **4.8**: Liquid Phase – Sample 19P – 100 % N_2

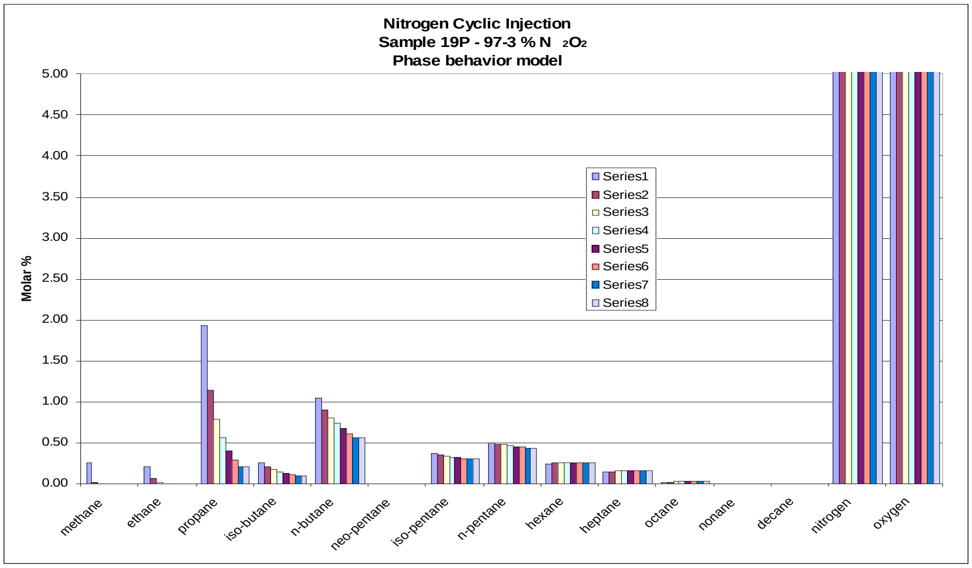

Figure **4.9** Vapor Phase – Sample 19P – 97-3% N_2O_2

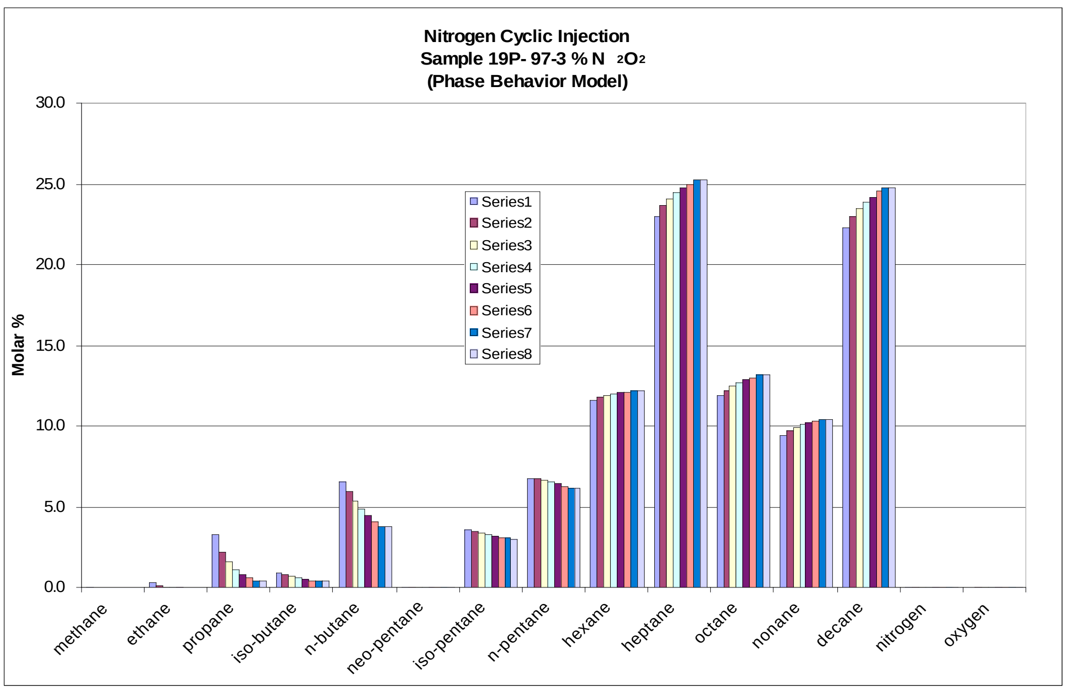

Figure **4.10**: Liquid Phase – Sample 19P- 97-3 % N_2O_2

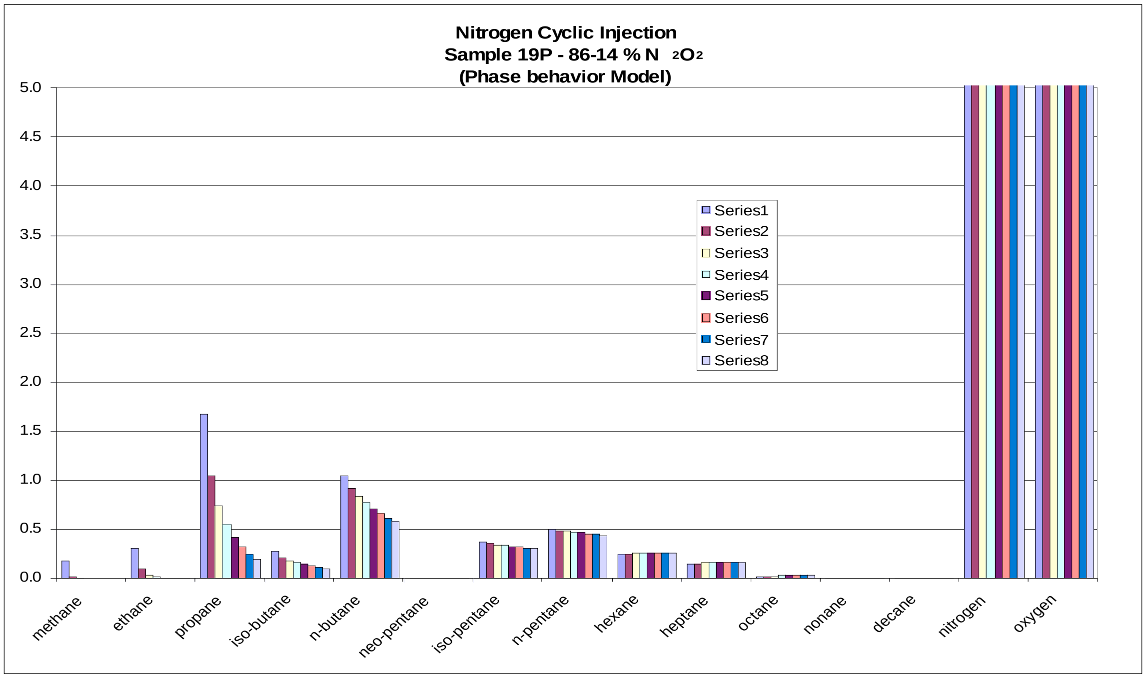

Figure **4.11**: Vapor Phase – Sample 19P – 86-14% N_2O_2

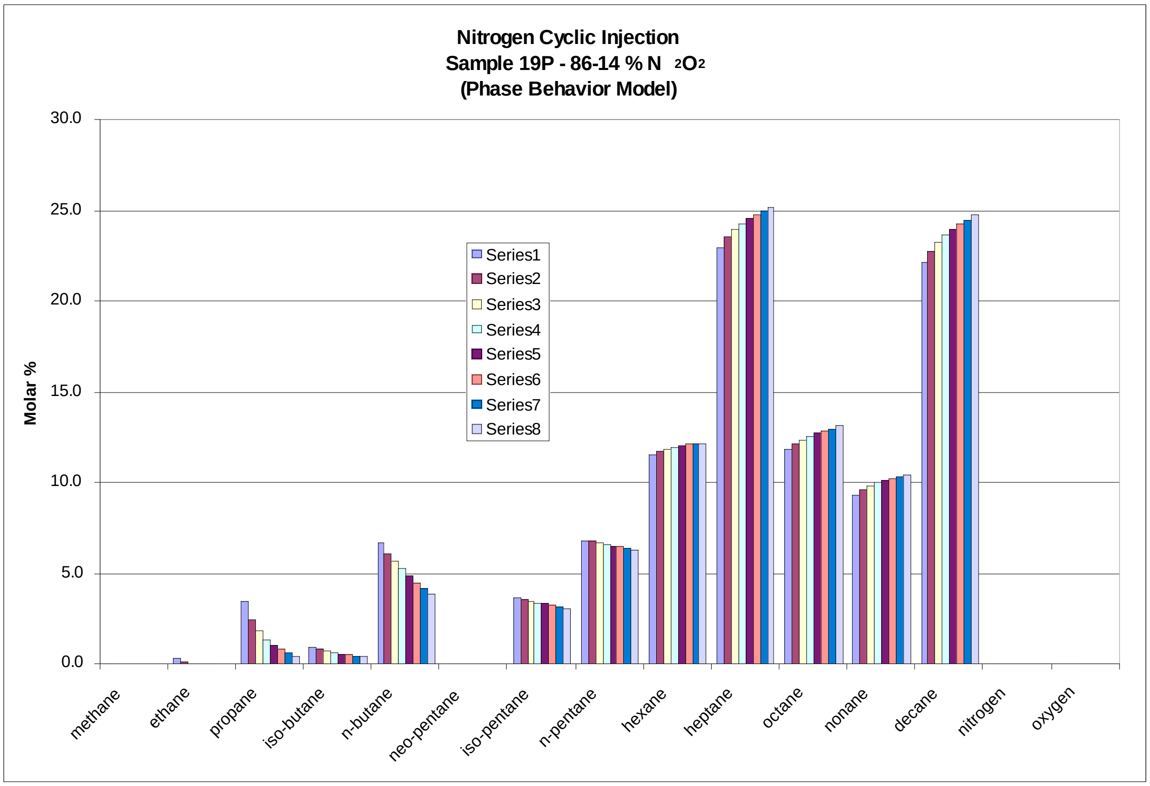

Figure **4.12**: Liquid Phase – Sample 19P – 86-14% N_2O_2

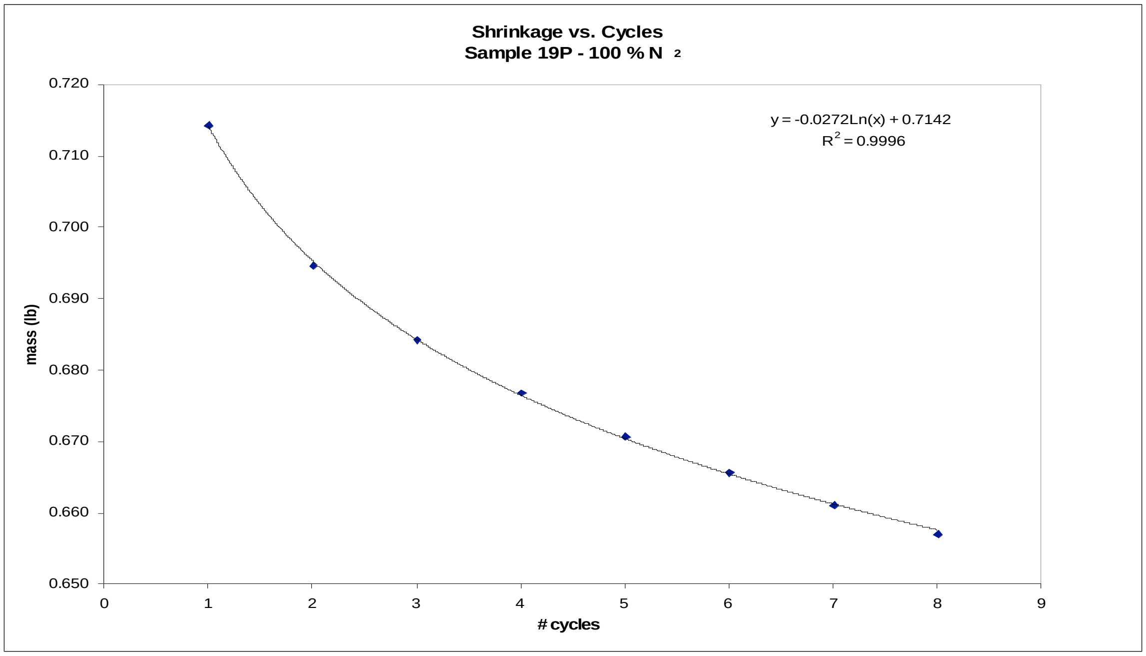

Figure **4.13**: Mass Shrinkage – Sample 19P – 100 % N_2

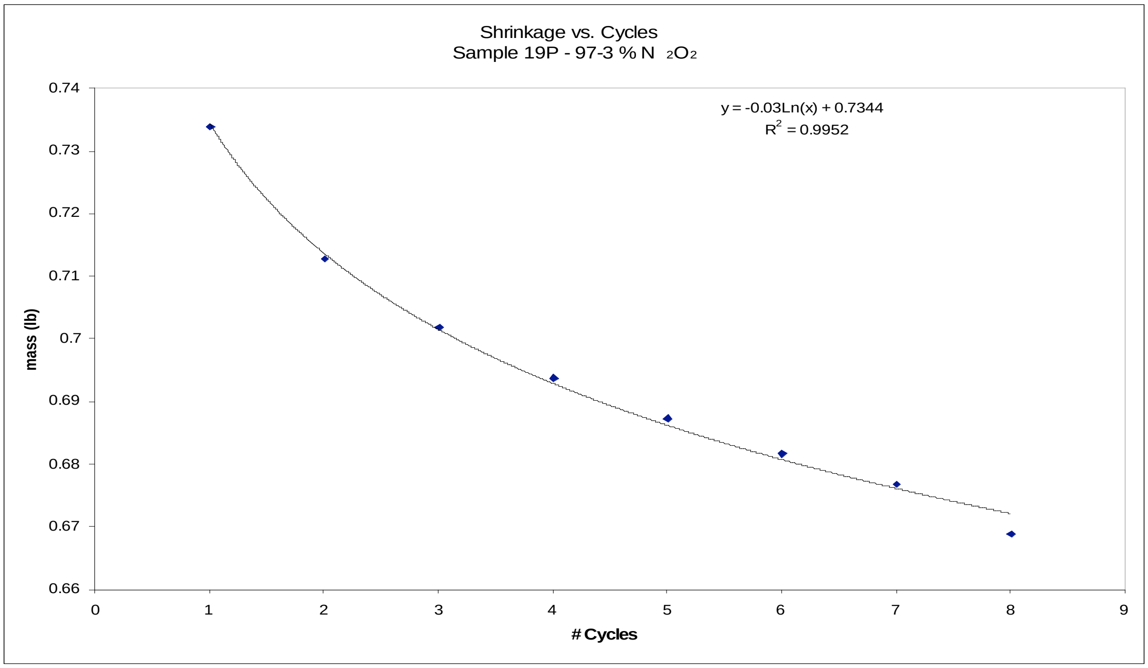

Figure **4.14**: Mass Shrinkage – Sample 19P – 97-3 % N_2O_2

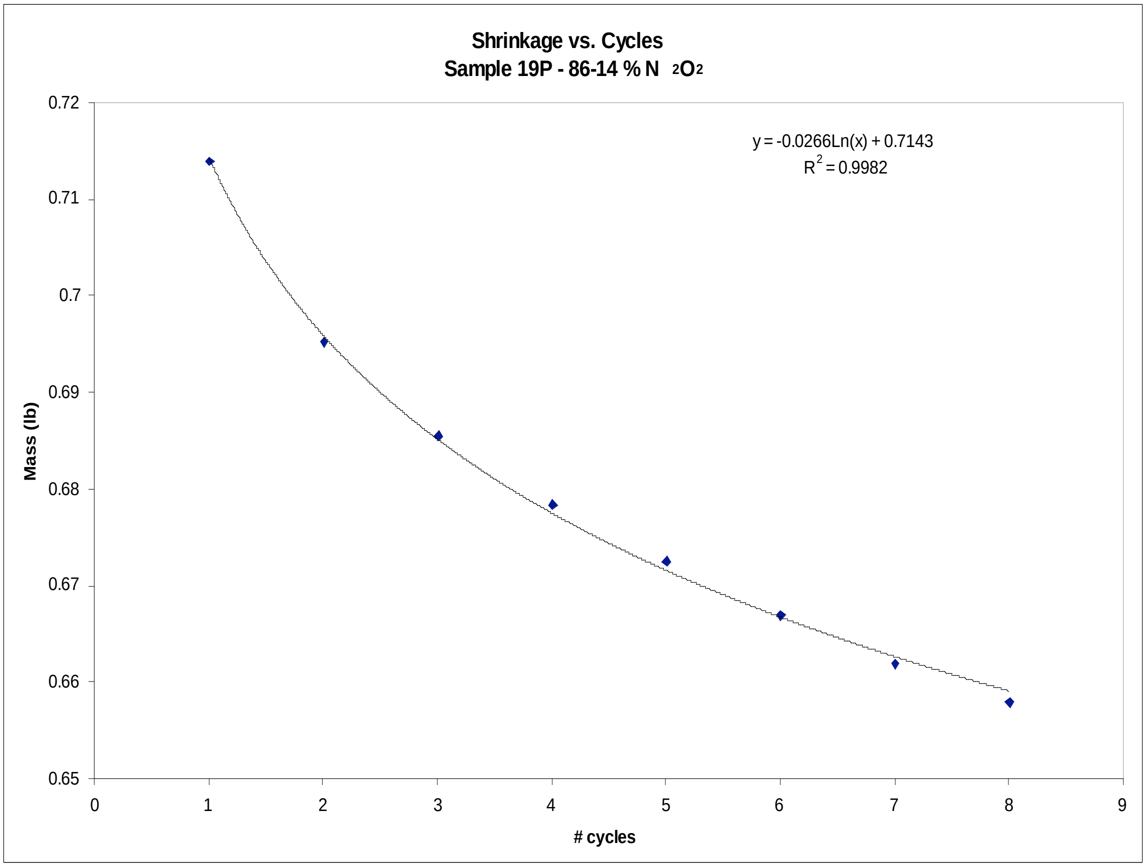

Figure **4.15**: Mass Shrinkage – Sample 19P – 86-14 % N_2O_2

CONCLUSION AND RECOMMENDATIONS

5.1 <u>Summary and Conclusions</u>

The objective of this study was to investigate the effects of nitrogen cyclic injection on the composition of crude oil and the extent to which nitrogen is vaporizing the crude oil. In order to do so, a PVT cell was used to conduct laboratory experiments and a phase behavior package was developed to model the results obtained from the laboratory. Cyclic injection experiments were conducted using nitrogen-oxygen mixtures using mid continental crude oil. The mixture of injected gas and oil was permitted to reach equilibrium through the use of 24 hour soaking period before performing the next cycle. A total of 6 cycles were conducted for each experiment. The vapor phase withdrawn from the PVT cell was analyzed at the end of each cycle using a gas chromatograph (G.C.) unit. The liquid phase was sent out to Questar Applied Technology for analysis only at the beginning and end of the experimental runs. The same experiment was done numerically using a phase behavior model. The results obtained from the PVT experiment were then compared to the results obtained from the phase behavior computer model. The parameters of the computer model were manually tuned to match the laboratory data as closely as possible. A total of 8 cycles of gas injection were made using the computer model. Based on the results obtained from the experimental work and the phase behavior model, the following conclusions were made:

1. Analysis of gas samples collected from the PVT cell have shown that nitrogen huff and puff injection at low pressures and temperatures (150 psig, 70ºF) resulted in stripping of the lighter end hydrocarbons from the crude oil sample. The intermediate through heavy components by contrast remain in the liquid phase. These results are consistent with the fact that more volatile gases have higher vapor pressure, hence have less cohesive forces than heavier components.

2. After 6 injection cycles of nitrogen gas injection, the density and viscosity of the crude oil indicated an increasing trend. This trend also prevails when the crude oil is mixed with an injection of nitrogen/oxygen mixture. Hence, both nitrogen and nitrogen/oxygen injection have increased the viscosity and density of the crude oil.

3. Shrinkage of the crude oil was computed from the data obtained and was found to increase with additional cycles of gas injection. This shrinkage did not appear to be significantly different when oxygen was mixed with the injected nitrogen. Further

study will have to be conducted in order to better understand the effect of oxygen on the shrinkage of the crude oil.

4. Varying the composition of the injected gas (i.e. N_2-O_2 fraction) did not have a significant impact on the composition of the vapor resulting from the mass transfer of lighter hydrocarbons from the crude oil. This was evident from the data obtained both experimentally and from the computer model.

5. Results obtained with using a phase behavior model indicated the same trend in composition as seen using the PVT cell. After performing 8 injection cycles a gradual decrease in stripping effect was observed. In terms of vapor composition, results obtained from varying the composition of the injected gas were not different from those obtained with pure nitrogen injection.

6. Starting with a given mass of crude oil, and injecting a constant volume of nitrogen for each cycle, it was found using the model that after 8 injection cycles, the mass of crude oil shrank by approximately 8.5 % by mass. In this study, shrinkage was attributed to the vaporization of the lighter components of the crude oil.

5.2 Recommendations for Future Research

Based on the results that were obtained and the observations that were made during this investigation, the following recommendations for future research were made:

1. Testing the injection process at different pressures (particularly higher pressures) could further identify the role that increasing the pressure has on the miscibility and vaporization of the crude oil using nitrogen-oxygen mixtures.

2. Monitoring the soaking phase by varying the duration of the soaking time and analyzing its effect on the stripping process could help optimize the injection-soaking-production cycles. For the case of the field work, the current 30-day soaking phase has not been tested against different times. Also, the 24-hour soaking period for the experimental work was not optimized.

3. Expanding the test matrix to include more nitrogen/oxygen and even nitrogen/CO_2 mixtures could further improve our understanding of the role played by the oxygen coupled with nitrogen and/or CO_2 on vaporizing the lighter ends of the crude oil and impacting the density and viscosity of the remaining liquid.

4. Expanding the PVT runs to include more injection cycles could further determine the extent of the vaporization effect. It was found that 6 to 8 cycles would only give an indication of vaporization but not the full extent of vaporization.

5. Core flooding to test the mobility of the injected gas relative to the reservoir crude oil could improve our understanding of reservoir processes involved in displacement.

6. Finally, a compositional reservoir simulation incorporating the physical processes present would help in analyzing the reservoir and provide insight necessary for efficient operation and future design.

REFERENCES

There are no references for this report.

LIST OF ACRONYMS AND ABBREVIATIONS

A	Parameter of the Peng-Robinson equation of state
B	Parameter of the Peng-Robinson equation of state
$\mathbf{b_m}$	Parameter of the Peng-Robinson equation of state
$\mathbf{V_m}$	molar volume, ft^3/lbmol
P	Fluid pressure, psia
R	Gas constant, ft^3-psia/ lbmol -°R
T	Temperature, ºR
MW	Molecular Weight, lb/mol
$\mathbf{f_i}$	fugacity of component i
$\mathbf{X_i}$	liquid molar fraction
$\mathbf{Y_i}$	Vapor molar fraction
$\mathbf{K_v}$	Parameter for the Lee-Gonzalez-Eakin gas viscosity equation
$\mathbf{T_{pc}}$	Pseudo critical temperature, ºR
$\mathbf{P_{pc}}$	Pseudo critical pressure, psia
$\mathbf{K_i}$	Equilibrium constant
$\mathbf{K_{ij}}$	Interaction coefficient

Abbreviations

API	American Petroleum Institute
IOR	Improved Oil Recovery
FID	Flame Ionized Detector

TCD	Thermal Conductivity Detector
PVT	Pressure Volume Temperature
GC	Gas Chromatograph
MSCF	Thousand Standard Cubic Feet
MMSCF	Million Standard Cubic Feet
STB	Stock Tank Barrel
OOIP	Original Oil In Place
BOPD	Barrels of Oil Per Day
EOS	Equation of State
MIOR	Microbial Improved Oil Recovery
BBLS	Barrels
TIOR	Thermal Improved Oil Recovery

Greek

Σ	summation
μ	viscosity
ρ	density
ε	error
ω	Pitzer's acentric factor
ζ	Clark's correlation
Φ	fugacity
α	Molar fraction

Table **A.1**: Composition - Sample 19P – 100 % N_2

Sample 19P - 100 %N2 - Vapor Phase

	run1	run2	run3	run4	run5	run6	run7	run8
methane	0.20	0.01	0.00	0.00	0.00	0.00	0.00	0.00
ethane	0.24	0.07	0.03	0.01	0.01	0.00	0.00	0.00
propane	1.86	1.14	0.79	0.58	0.43	0.32	0.24	0.18
iso-butane	0.26	0.21	0.18	0.15	0.13	0.12	0.10	0.09
n-butane	1.01	0.88	0.80	0.73	0.67	0.62	0.57	0.53
neo-pentane	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
iso-pentane	0.35	0.34	0.33	0.32	0.31	0.30	0.30	0.29
n-pentane	0.48	0.47	0.46	0.46	0.45	0.44	0.43	0.43
hexane	0.24	0.24	0.25	0.25	0.25	0.25	0.25	0.25
heptane	0.15	0.15	0.15	0.15	0.15	0.16	0.16	0.16
octane	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
nonane	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
decane	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
nitrogen	95.17	96.44	96.97	97.31	97.55	97.75	97.90	98.03

Sample 19P - 100 %N2 - Liquid Phase

	run1	run2	run3	run4	run5	run6	run7	run8
methane	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ethane	0.33	0.13	0.05	0.02	0.01	0.01	0.00	0.00
propane	3.40	2.37	1.73	1.28	0.96	0.72	0.54	0.41
iso-butane	0.99	0.85	0.74	0.64	0.57	0.50	0.44	0.39
n-butane	6.65	6.04	5.54	5.10	4.71	4.34	4.01	3.71
neo-pentane	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
iso-pentane	3.64	3.56	3.48	3.39	3.31	3.22	3.14	3.06
n-pentane	6.84	6.77	6.70	6.61	6.51	6.41	6.30	6.19
hexane	11.59	11.81	11.94	12.03	12.10	12.14	12.18	12.20
heptane	23.01	23.62	24.04	24.38	24.66	24.90	25.11	25.30
octane	11.86	12.20	12.44	12.64	12.81	12.96	13.09	13.21
nonane	9.41	9.68	9.88	10.05	10.18	10.31	10.42	10.52
decane	22.23	22.90	23.38	23.77	24.10	24.40	24.66	24.90
nitrogen	0.03	0.05	0.06	0.08	0.09	0.09	0.10	0.11

Table **A.2**: Composition - Sample 19P – 97-3 % N_2O_2

Sample 19P - 97-3 %N2O2 - Vapor Phase								
Compositon	**run1**	**run2**	**run3**	**run4**	**run5**	**run6**	**run7**	**run8**
methane	0.26	0.02	0.00	0.00	0.00	0.00	0.00	0.00
ethane	0.21	0.06	0.02	0.01	0.00	0.00	0.00	0.00
propane	1.93	1.15	0.79	0.56	0.40	0.30	0.22	0.22
iso-butane	0.27	0.21	0.18	0.15	0.13	0.11	0.10	0.10
n-butane	1.05	0.90	0.81	0.74	0.67	0.62	0.57	0.57
neo-pentane	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
iso-pentane	0.37	0.35	0.34	0.33	0.32	0.31	0.30	0.30
n-pentane	0.50	0.49	0.48	0.47	0.46	0.45	0.44	0.44
hexane	0.25	0.25	0.25	0.26	0.26	0.26	0.26	0.26
heptane	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.16
octane	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03
nonane	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
decane	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
nitrogen	72.32	72.77	73.11	73.33	73.49	73.60	73.69	73.70
oxygen	22.66	23.61	23.82	23.95	24.06	24.15	24.22	24.21
Sample 19P - 97-3 %N2O2 - Liquid Phase								
Compositon	**run1**	**run2**	**run3**	**run4**	**run5**	**run6**	**run7**	**run8**
methane	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ethane	0.32	0.12	0.05	0.02	0.01	0.00	0.00	0.00
propane	3.32	2.27	1.61	1.17	0.85	0.63	0.46	0.46
iso-butane	0.98	0.83	0.71	0.61	0.53	0.46	0.40	0.40
n-butane	6.59	5.96	5.42	4.95	4.53	4.15	3.80	3.79
neo-pentane	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
iso-pentane	3.63	3.54	3.45	3.35	3.26	3.17	3.07	3.07
n-pentane	6.83	6.76	6.67	6.56	6.45	6.34	6.22	6.22
hexane	11.61	11.83	11.96	12.05	12.11	12.15	12.18	12.18
heptane	23.07	23.69	24.14	24.49	24.78	25.03	25.25	25.25
octane	11.89	12.24	12.50	12.71	12.89	13.04	13.18	13.18
nonane	9.43	9.72	9.93	10.10	10.25	10.38	10.49	10.49
decane	22.29	22.98	23.49	23.90	24.25	24.56	24.84	24.84

Table **A.3**: Composition - Sample 19P – 86-14 % N_2O_2

Sample 19P - 86-14 %N2O2 - Vapor Phase								
Comp	**run1**	**run2**	**run3**	**run4**	**run5**	**run6**	**run7**	**run8**
methane	0.18	0.01	0.00	0.00	0.00	0.00	0.00	0.00
ethane	0.31	0.10	0.04	0.02	0.01	0.00	0.00	0.00
propane	1.68	1.04	0.75	0.56	0.42	0.32	0.25	0.19
iso-butane	0.27	0.22	0.19	0.16	0.14	0.13	0.11	0.10
n-butane	1.05	0.92	0.84	0.78	0.72	0.67	0.62	0.58
neo-pentane	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
iso-pentane	0.37	0.35	0.34	0.33	0.33	0.32	0.31	0.30
n-pentane	0.50	0.49	0.48	0.47	0.47	0.46	0.45	0.44
hexane	0.25	0.25	0.25	0.25	0.26	0.26	0.26	0.26
heptane	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.16
octane	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03
nonane	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
decane	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
nitrogen	81.35	81.74	82.09	82.37	82.61	82.80	82.97	83.10
oxygen	13.85	14.69	14.82	14.85	14.86	14.84	14.83	14.82
Sample 19P - 86-14 %N2O2 - Liquid Phase								
Comp	**run1**	**run2**	**run3**	**run4**	**run5**	**run6**	**run7**	**run8**
methane	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ethane	0.34	0.14	0.06	0.03	0.01	0.01	0.00	0.00
propane	3.49	2.50	1.86	1.40	1.07	0.82	0.64	0.49
iso-butane	1.00	0.87	0.76	0.67	0.59	0.53	0.47	0.42
n-butane	6.70	6.14	5.67	5.25	4.87	4.52	4.20	3.90
neo-pentane	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
iso-pentane	3.64	3.57	3.50	3.42	3.34	3.27	3.19	3.11
n-pentane	6.84	6.79	6.72	6.64	6.55	6.46	6.37	6.27
hexane	11.58	11.78	11.91	12.00	12.07	12.12	12.16	12.18
heptane	22.96	23.54	23.95	24.28	24.55	24.79	25.00	25.18
octane	11.83	12.15	12.39	12.58	12.75	12.89	13.02	13.13
nonane	9.39	9.65	9.84	10.00	10.13	10.25	10.36	10.45
decane	22.18	22.81	23.27	23.64	23.97	24.25	24.51	24.74
nitrogen	0.02	0.04	0.05	0.06	0.07	0.08	0.08	0.09
oxygen	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01

Table **A.4**: Tuned PR- Interaction Coefficients

	Methane	Ethane	Propane	Iso-butane	butane	neo-pent	iso-pent	pent	hexane	heptane	octane	nonane	decane	nitrogen
methane	0	0.005	0.01	0.015	0.015	0.018	0.018	0.018	0.019	0.02	0.025	0.03	0.035	70.018
ethane	0.005	0	0.002	0.003	0.003	0.005	0.005	0.005	0.007	0.01	0.015	0.017	0.021	40.039
propane	0.01	0.002	0	0.001	0.001	0.002	0.002	0.002	0.004	0.005	0.007	0.009	0.011	10.046
iso-butane	0.015	0.003	0.001	0	0.001	0.009	0.008	0.008	0.01	0.012	0.015	0.017	0.02	5.047
n-butane	0.015	0.003	0.001	0.001	0	0.001	0.001	0.001	0.003	0.005	0.007	0.009	0.011	5.047
neo-pentane	0.018	0.005	0.002	0.008	0.001	0	0.001	0.001	0.005	0.002	0.003	0.005	0.007	0.048
iso-pentane	0.018	0.005	0.002	0.008	0.001	0.001	0	0.001	0.003	0.005	0.007	0.009	0.011	0.048
n-pentane	0.018	0.005	0.002	0.008	0.001	0.001	0.001	0	0.002	0.003	0.005	0.007	0.009	0.048
hexane	0.019	0.007	0.004	0.009	0.003	0.005	0.003	0.002	0	0.003	0.005	0.005	0.008	0.05
heptane	0.02	0.01	0.005	0.01	0.005	0.002	0.005	0.003	0.003	0	0.005	0.006	0.007	0.055
octane	0.025	0.015	0.007	0.012	0.007	0.003	0.007	0.005	0.005	0.005	0	0.005	0.007	0.06
nonane	0.03	0.017	0.009	0.015	0.009	0.005	0.009	0.007	0.005	0.06	0.005	0	0.007	0.065
decane	0.035	0.021	0.011	0.017	0.011	0.007	0.011	0.009	0.008	0.07	0.007	0.007	0	0.07
nitrogen	70.018	40.039	10.046	5.047	5.047	0.048	0.048	0.048	0.05	0.055	0.06	0.065	0.07	0

TITLE PAGE

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Establishing Programs to Reimburse Operators for Produced Water Desalination

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Establishing Programs to Reimburse Operators for Produced Water Desalination

Executive Summary

Management and disposal of produced water is one of the most challenging problems associated with the oil and gas industry. Very large volumes of produced water are produced along with the oil and gas resources. Handling produced and injected water is a major emphasis in the industry today, both in mature oil leases and in newer production from unconventional gas reserves such as coal bed methane (CBM). The treatment of wastewater, its effects on the environment, and a growing concern for the availability of water in arid lands is no longer just an engineering issue but is no a social issue as well.. Current brine management methods, such as re-injection of the produced water back into the reservoir is often not an option. Other methods such as impoundment and re-use for beneficial purposes are costly to the industry, a concern to the environmental community, and a headache to the regulatory bodies responsible for oversight. .

The first Stripper Well Consortium (SWC) project funded at Texas A&M University was "*Environmental and Regulatory Issues Relating to the Utilization of Produced Water from Oil & Gas Operations*", a study of the existing policies of two oil and gas producing regions. With the support of the SWC, A&M developed guidelines for companies to follow for making this new source of fresh water available for productive use. We met with appropriate agencies as new rules and regulations were being considered and worked with those seeking to remove some of the roadblocks to the re-use of treated produced water.

The first project addressed regulatory practices that are encountered when developing a produced water reuse program. This second project focuses on economic incentives to reimburse operators who choose to re-use produced water for beneficial purposes. It is a part of the overall A&M program to promote the beneficial re-use of produced water resources from oil and gas operations.

The goal of this second SWC project has been to identify market mechanisms to repay those willing to develop this new and unconventional source of fresh water. Our work includes (1) upgrading existing prototype units, (2) operating short and long-term field testing with full size process trains and (3) identifying practices in which environmental and oil and gas regulatory agencies can reimburse those who adopt such practices.

Testing at A&M has included extended testing in "field laboratories" to gather much needed extended run time data on filter salt rejection efficiency and plugging characteristics of the process train. This information is needed by operating companies and regulatory agencies when they consider their support for a significant, if unconventional, new source of fresh water resources.

Results of Project

Our program has been well received by industry and the government. We have successfully demonstrated that produced water can be treated at less expense than transporting it to commercial disposal wells off-site. We have worked with private companies and public agencies to identify reimbursement mechanisms, in effect how to receive value for this new found resource.

In Texas, Governor Perry and the Texas Water Development Board (TWDB) have been providing leadership for the state in developing desalination programs, including treatment of waste water and oil field brine. However, environmental and regulatory issues related to desalination of produced water in Texas clearly inhibit technology advancement of this resource. Cost reduction advancements in technology are slowed by a lack of a clear “path to market” of new products and processes. It is hoped that this SWC project will add a different perspective to discussions about water sources for desalination, conveyance issues associated with water transfer, and the demand for the resource if it were to be made available.

Local issues that communities would identify as barriers must still be addressed at the local level. Barriers include the perception that desalinated produced water is not pure enough for consumption by humans or livestock and that there might be environmental drawbacks to its use for plants, range, and habitat sustainability. Advanced technology and an improved regulatory climate is improving the likelihood of adoption of produced water desalination by water use groups in the state.

The Texas A&M program is sponsored by the Stripper Well Consortium (SWC), the Global Petroleum Research Institute (GPRI), and by the Texas Water Resources Institute (TWRI) It is also endorsed by the Texas Railroad Commission, the agency responsible for regulating the oil and gas industry in Texas and the Texas Water Development Board.

Establishing Programs to Reimburse Operators for Produced Water Desalination

Section 1

Background and Previous Work

Management and disposal of produced water is one of the most challenging problems associated with the oil and gas industry. Very large volumes of produced water, or brine, are produced along with the oil and gas resources. Handling produced and injected water is a major emphasis in the industry today partly to the increasing importance of coal bed methane (CBM). The treatment of wastewater, its effects on the environment, and a growing concern for the availability of water in arid lands is no longer just an engineering issue but is no a social issue as well.. Current management methods available, such as re-injection of the produced water back into the reservoir is often not be an option. Other methods such as impoundment and re-use for beneficial purposes are costly to the industry, a concern to the environmental community, and a headache to the regulatory bodies responsible for oversight. .

Texas has long been one of the top petroleum producing states in the nation. As fields have matured, more brine water is produced along with the petroleum resource. More brine water is being re-injected as well, to sustain production, prevent subsidence, and to dispose of excess produced brine. It is ironic that Texas has long been struggling with a lack of water resources too, especially in West Texas. As the population of the state grows, more demand be being placed upon surface and ground water sources of fresh water. Why hasn't produced water been used as an additional source of water?

The simple answer is that untreated produced brine has contaminants that make it unpalatable for humans or livestock. Re-injection of the brine back into the formation from where it was produced has been the least expensive; hence preferred disposal method for brines. Large quantities of produced water are brought to the surface in Texas as a result of various natural resource extraction activities. The composition of this produced fluid is dependent on whether crude oil or natural gas is being produced and generally includes a mixture of either liquid or gaseous hydrocarbons, produced water, dissolved or suspended solids, produced solids such as sand or silt, and injected fluids and additives that may have been placed in the formation as a result of exploration and production activities.

The Texas A&M desalination program, sponsored by the Texas Water Resources Institute (TWRI) is seeking to determine whether desalination of produced brine offers promise as a source of fresh water resources. Research is currently underway at a number of companies to assess the economic and technological feasibility of desalting this product water to develop water of sufficient quality to meet certain local water supply needs and to allow consideration of disposal options other than well injection. With the assistance of the Stripper Well Consortium (SWC) we are working to further the technology and put it into commercial practice.

Specific research needs are harder to prioritize. For the past three years A&M has worked to find technologies to employ in desalination and to outline ways to establish a value for the resource that is recovered by this treatment. The group (led by this author) unequivocally states that the technology is available to desalinate certain brines produced in petroleum operations. However that technology needs to be improved, the value of fresh water and local water supply needs must be established, and the environmental and regulatory issues associated with beneficial use must be addressed.

Produced Water Management in Oil and Gas Industry

In the oil and gas industry, standard water management operations include handling large volumes of produced brine. These operations offer a novel and unique approach to re-injection of saline RO concentrate from the desalination process into oil and gas producing zones.

Oil and gas operations produce copious amounts of brine water along with the associated petroleum resource. Produced water, (any water that is present in a reservoir with the hydrocarbon resource) is produced to the surface with the crude oil or natural gas. The oil and gas industry is experiencing increased volume of produced water handled in both onshore and offshore petroleum production operations. The resulting operational costs and environmental issues are becoming a major concern, especially with the possibility of further reduction in the oil content allowed in the discharged water (offshore operations) , as well as the fact that produced water contains a number of undesirable toxic components. Figure 1 shows a slide from Shell Oil Company on that company's production of brine worldwide in the past decade[1].

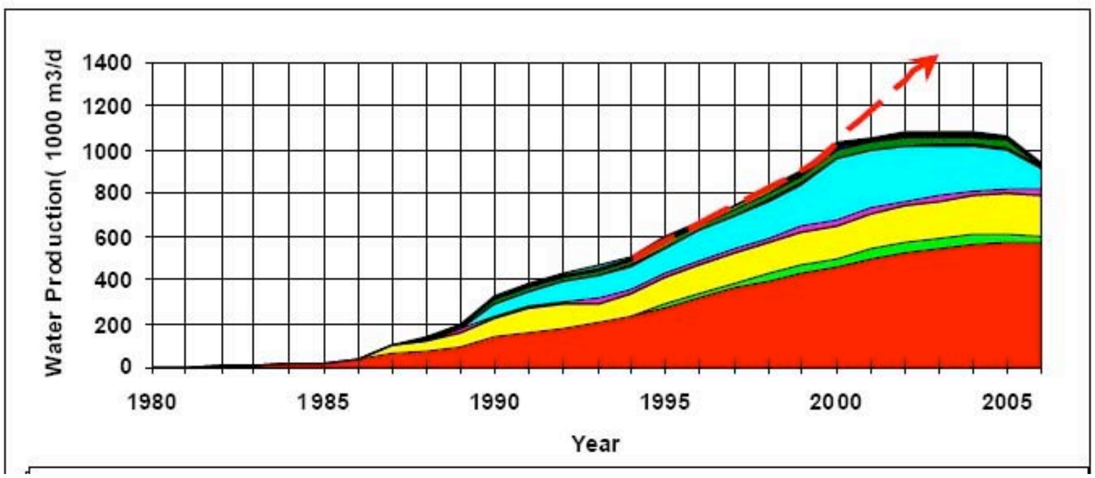


Figure 1 shows oil field produced water volume trends in each of the five major operating areas for Shell Oil. (1,000 m^3 = 6289 bbls). The trend increases in each of the areas until (assumed) new technology can intervene.

For the United States, the American Petroleum Institute estimated about 18 billion barrels per year were generated from onshore wells in 1995, and similar volumes are generated today. Offshore wells in the United States generate several hundred million barrels per year of produced water. Internationally, three barrels of water are produced for each barrel of oil. Production in the United States is more mature; the U.S average is about 7 barrels of water per barrel of oil. Closer to home, in Texas the Permian Basin averages more than 9 of water per barrel of oil and represents more than 400 million gallons of water per day processed and re-injected[2]. New technology is needed to forestall these trends.

To speed up the adoption of new technology, the industry is gradually adopting new technology for handling produced water both in mature fields and in new and planned developments. Innovative programs take into consideration the nature of the water, technology limitations, both emission to the atmosphere and discharges into the sea, nature of the discharges, safety concerns and cost, as well as establishing any environmental gains in each case. In this procedure companies such as Shell use a systematic empirical ranking and indicator tool applied to the different aspects of the alternative options considered. Most operators, big and small handle produced water management in the same way. Most often in Texas however, the option is brine injection back into the producing formation.

In another industry, lack of water is the critical factor. A water crisis is looming in many parts of the United States. Areas in the American West and Southwest are especially critical, with many areas currently coping with a series of droughts that have significantly altered land-use behavior and impacting both urban and rural communities. Throughout these regions, water quantity and quality issues increasingly are being recognized by state policy makers, local elected officials, and the citizenry at large. In Texas, data available from the Texas A&M Cooperative Extension[3] (TCE) show the pervasiveness of these concerns in the state (TCE 1999). In 1999, TCE, in a major planning effort, gathered information from over 10,000 Texas residents on critical issues confronting their communities. Those issues associated with water quantity and quality ranked among the top five priorities in 184 of the state's 254 counties (TCE 1999). It is apparent that solutions to the pressing water quantity and quality issues in Texas and other states will require innovative approaches and technologies.

Technology currently exists to remove contaminants from produced water and to create a resource that could be used to supplement current water supplies in water-short regions. Texas A&M's Texas Water Resources Institute (TWRI)[4] is planning two projects in Texas to utilize fresh water recovered from oil field brine to rehabilitate rangelands and wildlife habitats. The program involves environmental monitoring of test plots where natural rainfall is augmented though the use of fresh water produced by portable water treatment modules. The field project is expected to show that native grasses can be re-established in degraded areas safely at a rate more than 8 times faster than comparable methods of rangeland restoration.

Several impediments to the widespread adoption and diffusion of water treatment technology such as the TWRI program must still be addressed. First, there are no market mechanisms and incentives currently in place for the oil and gas operators to treat water and make it available as a commodity. Oil and gas companies produce petroleum, not fresh water. They see the water produced with petroleum as a waste, not a byproduct to be re-used. Second, it is not clear if members of the general public are aware of the produced water technology and the potential benefits that could be derived from the development of this resource. Even if oil and gas companies began producing treated water, we do not know the extent to which individuals would be willing to accept its use.

And third, current local, state, and federal regulations classify produced water as a waste material, not a byproduct to be treated and reused. Texas A&M, like the ranchers in New Mexico[5], believes that produced water represents a resource not to be wasted.

Fresh Water Resources from an Oil Field Brine

This report discusses water management options specific to independent operators. Options such as produced water impoundment and release, re-injection, and resource recovery all are options for our industry. There are many opportunities for using produced water. However, the ability to identify an alternative as being feasible will likely be dependent upon very site-specific and situation-specific criteria. Fresh water resource recovery from produced water is the example cited in our work, but other options are available.

It is important to note that the rules and regulations relating to impoundments and the coal bed methane (CBM) industry in the West are currently being modified or developed for several states. Reviewers who can provide regulatory clarification or updates to the regulatory section of this document would be appreciated.

The impoundment of produced water from CBM production can be an option utilized by operators as part of their water management practices. In some producing basins, such as the Powder River Basin, impoundments play a large role in water management practices, while in other basins impoundments may only be used during drilling operations.

Current Regulations

Produced water is saltwater or brine that is produced along with hydrocarbons during the exploration and production processes of the petroleum industry. In some cases, the volume of water produced may exceed the volume of hydrocarbon production. The disposal of this water becomes costly to the industry. Discharge of produced water to the surface waters and seawaters is prohibited under the Clean Air and Water Act until certain criteria are met[6]. The maximum allowable amount of petroleum hydrocarbons in produced water that can be discharged is 29 ppm. Discharge of produced water is not allowed on land and in streams and rivers where the produced water may come in contact with surface water.

Regulatory Considerations Impacting BW/PW Desalination

This section of the paper discusses some of the possible regulatory requirements that would come into play if the RO concentrate is injected for either secondary recovery of hydrocarbon resources or for disposal. This analysis gives some indication of the uncertain nature of the regulatory environment and the fact that different regulators may use different regulatory mechanisms. This information has been provided by Mr. John Veil of Argonne National Laboratories and summarized in SPE 86526 [7].

The U.S. Environmental Protection Agency (EPA) administers the Underground UIC program. The UIC regulations define injection well as "a well into which fluids are being injected". A well is "a bored, drilled, or driven shaft whose depth is greater than the largest surface dimension; or, a dug hole whose depth is greater than the largest surface dimension; or, an improved sinkhole; or, a subsurface fluid distribution system". The UIC regulations place injection wells into five classes. Most Class I wells are used to inject hazardous wastes, but some Class I non-hazardous wells are used for disposal of non-hazardous materials. For Class I wells, this injection must occur below any formations that have an underground source of drinking water (USDW) within one-quarter mile of the well bore. Class II wells are used in the oil and gas industry and are particularly relevant to reinjection of RO concentrate when the source water is produced water. Class III wells are used for solution mining. Class IV wells are used to inject hazardous or radioactive wastes into or above a formation that includes a USDW within one-quarter mile of the well bore – these are banned. Finally, Class V wells include all other injection wells not placed in any of the other classes.

Table 1 indicates the responses from several states and EPA. All are consistent on scenarios 1 and 2, and all but Texas are consistent on scenario 3 – these would unequivocally be regulated as Class II wells. This follows directly from the Class II well definition shown above. Because produced water is used as source water in scenarios 1 and 2, subsequent injection of the concentrate is consistent with the first category of Class II wells (injection of fluids brought to the surface in connection with oil and gas production). Under scenario 3, the concentrate is used for enhanced recovery, thereby matching the second category of wells under the Class II definition (injection for enhanced recovery). Texas does not rule out permitting these wells as Class II, but suggests that it would need to review the determination between its Railroad Commission (the oil and gas regulatory agency) and the Commission on Environmental Quality (regulates all other environmental issues).

Scenario 4 presents a different situation because neither the source water nor the injectate meet the definition of a Class II well. Some agencies suggest that injection of the concentrate would be made into a Class I well, and the chemical characteristics of the well would determine if the well would be a hazardous or nonhazardous well. Utah suggested that injection could be made into a Class V well. The difference between Class I and Class V is quite significant. Class I wells are subject to very stringent design, construction, operation, and monitoring requirements, whereas Class V wells are regulated in a less stringent manner. The costs of constructing and operating a Class I well are much higher than comparable costs for a Class V well.

In general, the two key factors used to determine which well class would be assigned for concentrate injection under scenario 4 are the depth of the injection zone in relation to the depth of the lowermost USDW and whether the constituents of the concentrate are considered to be hazardous materials or not. If the injection occurs above or directly into a USDW and the concentrate is nonhazardous, the well could be permitted as a Class V well. Injection of hazardous concentrate into or above a USDW is prohibited. If the injection occurs below the USDW, the well would be a Class I well, and the nature of the concentrate would determine if the well would be Class I hazardous or Class I nonhazardous.

To further complicate the picture for scenario 4, California reports that if the RO concentrate is not hazardous, the Department of Oil, Gas, and Geothermal Resources may try to permit the injection as part of a Class II well. They acknowledge that in the past, the agency has occasionally authorized injection of non-oil-field wastes into Class II wells with the caveat that the permit had restrictions on total volume and the duration of the injection. If the concentrate is hazardous, its injection would require a Class I well.

Table 1. Regulatory Practices Pertaining to Re-injection of Water into Underground Formations (Burnett & *Veil*[7])

State	Produced Water		Saline Groundwater		Reference (based on emails to or phone conversations with John Veil, Argonne National Laboratory, on the dates indicated)
	Enhanced Recovery Scenario	**Disposal Scenario**	**Enhanced Recovery Scenario**	**Disposal Scenario**	
California	Class II well	Class II well	Class II well	If concentrate were not hazardous, they would consider permitting as a Class II well. If hazardous, they would use a Class I well.	Michael Stettner, California Division of Oil, Gas, and Geothermal Resources, October 6, 2003
New Mexico	Class II well	Class II well	Class II well	Depending on the characteristics of the concentrate, the well would be permitted as Class I hazardous or Class I nonhazardous.	Roger Anderson, New Mexico Oil Conservation Division, October 2, 2003
Oklahoma	Class II well	Class II Well	Class II well	Class I nonhazardous well. That would be regulated by the Oklahoma Department of Environmental Quality	Tim Baker, Oklahoma Corporation Commission, October 6, 2003; Hillary Young, Oklahoma Department of Environmental Quality, October 6, 2003.
Texas	Class II well	Class II well	In both cases, the Railroad Commission (regulates oil and gas activities) would confer with the Texas Commission on Environmental Quality. Depending on their decision the wells could be Class II or Class I		Fernando De Leon, Railroad Commission of Texas, October 6, 2003
Utah	Class II well	Class II well	Class II well	Class V well. That would be regulated by the Utah Department of Environmental Quality	Dan Jarvis, Utah Division of Oil, Gas, and Mining, October 2, 2003
U.S. EPA	Class II well	Class II well	Likely a Class II if the volume allows.	Depends on the characteristics of the concentrate and whether the injection zone was above or below a USDW.	Bruce Kobelski, U.S. EPA headquarters, Office of Groundwater and Drinking Water,

Presently, injection of RO concentrate is not a common practice. If the practice becomes more common in the future, states or the EPA may adopt new policies or regulations to govern concentrate injection.

Water Problems Caused in Part by Conflicting Regulations

Management and disposal of produced water is one of the most significant problems associated with the oil and gas industry. In Texas, more than 150,000,000 gallons of water are produced in the industry each day. The management and disposal of this water becomes very costly to the industry, as well as becoming a possible reservoir and environmental hazard. The current method commonly used throughout the petroleum industry today is reinjection of the water produced during exploration and production. This costs up to $1.50 per barrel of produced water. The preferred method for the disposal of produced water is one that adequately protects the environment and is of the lowest cost to the operator. Regulatory and monetary constraints often limit the options available, however.

The Texas Commission on Environmental Quality (TCEQ) estimates that by the year 2020, fresh water needs in the state of Texas will increase by more than twenty times[8]. There are many arid regions, such as West Texas, with little fresh water resources, but with large amounts of oil, gas, and brine production. According to the Texas Railroad Commission, an excess of 400 million gallons of water are produced from oil and gas wells in the Permian Basin of West Texas with only one percent of the produced water being used at the well locations. The remaining 99% is disposed of by reinjection. The oil and gas industry is now looking into ways of using the vast amounts of produced water to benefit these areas in which a scarcity of water exists. With new technologies in the oil and water separation and desalination processes, contaminants may be removed from produced water. This produced water may also be treated and converted into reuse quality for beneficial purposes, such as agricultural, rangeland and grassland restoration, site remediation, landscape watering, or water for oil field use. Presently, there are no clear-cut laws and regulations in the United States dealing with the beneficial use of produced water.

Section 2

Review of Current Project

Objectives & Significance of the Work

The project is a continuation of our previous SWC project and an integral part of an A&M program studying the beneficial re-use of produced water resources from oil and gas operations. Our long-term goals are to promote the more efficient management of waste water from the oil and gas industry, including produced water.

The specific objectives of this SWC project are (1) to demonstrate that treatment of oil field waste water for re-use will reduce water handling costs by reducing the need for new fresh water resources and reducing water handling and transportation costs and (2) to identify market mechanisms that provide incentives to those willing to pay the costs of developing this new and unconventional source of fresh water.

We hope to use this information and our relationships with regulatory agencies to present the case for underwriting the costs of this treatment that could provide a significant, if unconventional, new source of fresh water resources.

Description of Project

Our work included both laboratory and field testing of prototype systems and identifying practices in which environmental and oil and gas regulatory agencies can reimburse those who adopt such practices. Testing at A&M has allowed us to upgrade our existing unit and test it, first on campus at a water treatment plant then later in the field at a produced water disposal facility.

Task 1. Design and construct a system for removal of oil and other contamination materials from water used in well completion fracturing operations.

Produced brines and spent fracturing fluids contain a number of different types of ionic species, oil, colloidal particles, and heavy metals. We are testing new pre-treatment processes designed to reduce costs and maintenance and provide a more cost effective process design when compared with conventional filter train designs.

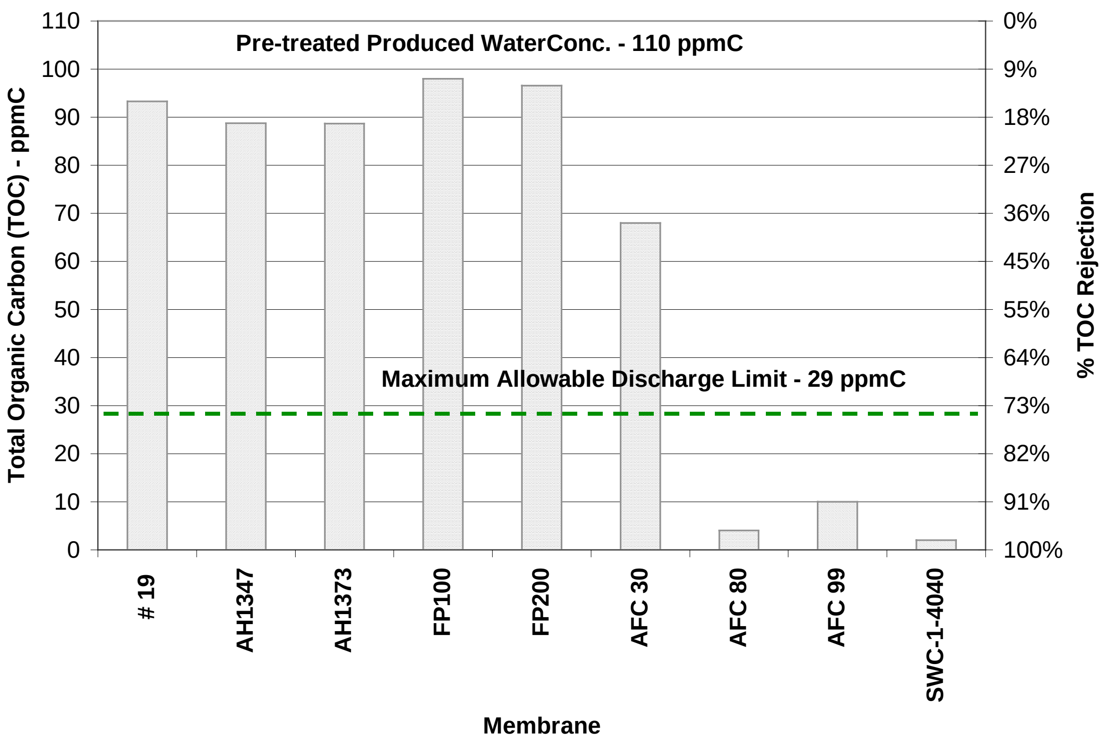
Membrane Selection Process

In early work, nine different membranes were evaluated to determine their efficiency in removing hydrocarbons and salts from the produced water[9]. Selection criterion for the membranes was based on the ability of the membrane to handle hydrocarbons and other organics, hydrophilicity, resistance to fouling by organics (oil), and rejection of dissolved solids. Membranes included one spiral, three ceramic, and five tubular membranes.

Produced water was collected from a facility located outside of College Station in Brazos County used for the disposal of produced water that is collected from the oil wells surrounding the College Station area. The produced water contained approximately 110 ppmC TOC (total organic carbon). The total dissolved solids (TDS) concentration of was about 45,000 ppm This produced water was used as feed for the membranes to determine their efficiency in removing the hydrocarbons and salts from the produced water.

Performance of these membranes are summarized in the Table.

Table 2 shows a comparison of the oil rejection characteristics of 9 types of membranes. (*Siddiqui*[9])



Based on the results of these experiments, the desalination unit was reconfigured to test pre-treatment at the water treatment facility on campus.

Figure 2 shows the reconfigured unit prior to loading on the desalination trailer.

A&M Desalination Unit

Components of the mobile water treatment unit were assembled and tested at Tarlton Manufacturing and at the Separation Pilot Plant on the A&M campus. The mobile unit contained a transformer to step down field electrical power from 440 v to 220v and an electrical meter to monitor power usage during testing. All electrical equipment was connected through the master panel. The trailer was quipped with three types of pre-treatment equipment including (1) a powered centrifuge, (2) organoclay absorbent canisters and (3) microfiltration crossflow membrane filtration test apparatus.

To test the mobile unit, we set up a field test at the Texas A&M Brayton Fire Fighter Training School on the west campus. This facility has several large ponds where run off water from firefighting drills collected before being recycled through the fire pumps.

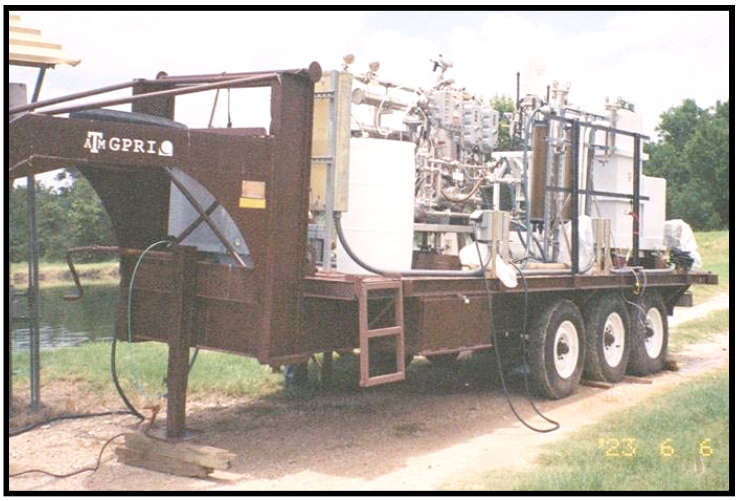


Figure 3 shows the mobile unit rigged for towing to a field site.

Figure 3 shows the mobile unit configured for pre-treatment testing. At the front of the unit the power transformer steps down the power to 220 volts and monitors power usage. The center of the unit contains the portable membrane test apparatus. Behind the membrane unit sits a pair of organoclay containers while at the rear of the trailer the powered centrifuge serves to treat input water with high concentrations of suspended solids.

Figure 4 shows the unit in operation at the Brayton test site. Raw water containing biomass, oil, suspended solids, and oil are pumped through the pre-filter unit and cleaned. Cleaned water and reject concentrate were pumped back into the pond. The system worked sufficiently well that further field tests were scheduled.

Figure 4 shows the unit in operation at the firefighter training school.

Testing at the waste water pond at Brayton provided us with a better idea of how the system should operate in the field. The field trial provided performance data on (a) the powered centrifuge, (b) Performance of micro-filter membrane and (c) the performance of organoclay canisters. We also decided to redesign the microfiltration cleaning procedures after traditional methods were deemed too inefficient.

The following Table shows details of our early cleaning process.

Table 3. Cleanup of Membrane Filters

First Cleaning

Time	Pressure		Temp.	Permeate		Recir.	Retentate
	in	out		Rate(ml/sec)	Rate (gal/min)	gpm	gpm
12:00	10	4	37	23.0	**0.36**	10.38	5.32
12:07	15	10	37	50.0	**0.79**	10.18	4.55
12:14	20	15	37	78.0	**1.24**	10.25	3.43
12:16	25	22	37	108.0	**1.71**	10.25	2.8

Second Cleaning

Time	Pressure		Temp.	Permeate		Recir.	Retentate
	in	out		Rate(ml/sec)	Rate (gal/min)	gpm	gpm
1:40	10	4	37	28.5	**0.45**	10.25	5.74
1:45	15	10	37	58.5	**0.93**	10.25	4.48
1:48	20	16	37	86.5	**1.37**	10.18	3.29
1:52	25	22	37	110.0	**1.74**	10.25	2.38

Third Cleaning

Time	Pressure		Temp.	Permeate		Recir.	Retentate
	in	out		Rate(ml/sec)	Rate (gal/min)	gpm	gpm
3:50	10	5	38	26.0	**0.41**	10.18	5.74
3:55	15	11	38	60.0	**0.95**	10.18	4.41
3:57	20	15	38	83.0	**1.32**	10.117	3.29
4:00	25	20	38	112.5	**1.78**	10.18	2.45

Because of the importance of keeping membranes clean, a new research project has been created to develop new cleaning methods for membranes. Details of that program are at www.gpri.org (brine treatment).

Task 2. Evaluate desalination performance in extended tests.

Task 2 included tests on the field unit operation, first at the A&M campus site, then in Decatur Texas at Key Energy Denton Creek disposal facility. The field facilities support Burlington Resources and other operator's Barnett Shale fracturing operations.

Figure 5 shows trucks queuing at the Denton Creek facility unloading dock. The site (in 2004) received as many as 40 trucks a day representing more than 5,000 bbl brine disposed per day.

Figure 5. Brine transport trucks waiting to unload at the Denton Creek facility. At one time in late 2004, the Texas Railroad Commission had received more than 40 applications for disposal well operations in Wise County Texas.

The desalination trailer was taken to the Denton Creek facility and tested in December of 2004. It had been modified to the new test conditions expected at the site. The trailer is shown in Figure 6. A 250 gallon polyethylene water tank replaced the powered centrifuges unit and a large tool box (red container) was placed on the trailer to serve as a storage and tool locker. Desalination operations were performed under the supervision of Mr. Carl Vavra of the Separation Sciences section of the Texas A&M Food Protein Research Center.

Figure 6. Desalination trailer at Denton Creek. Fresh water had to be transported to the site to ensure cleaning and startup would not damage the membranes.

Our milestone goal for these extended duration tests had been to process at least 1,000,000 gallons of brine in order to obtain accurate data on power requirements and membrane fouling. The tests were stopped early (100,000 gallons processed) because of a mechanical failure unassociated with membrane performance. However sufficient information was collected to classify the test as a success. The following Table contains test data from our laboratory and field tests and from a field pilot performed by NATCO Oil Field Services (Frankowicz and Lee [10]).

Table 4. Recovery efficiency and operating cost of membrane treatment.

Process Description	Membrane Type, (TMP[a])	Brine composition, TDS	Recovery efficiency,%, (Q, gpm)	Operating Costs $/1,000 gallons
Pre-treatment	Microfiltration, 25 psi	Fresh water with TSS, oil, & biofilm	20% (3.2)	$0.84
Desalination[b] (single stage)	"Open" RO, (235)	Simulated brackish water	1%,).02 est.	NR
Pre-treatment	Microfiltration, (45 psi)	20,000 TDS oil field brine	25%, (2.5)	$3.24
Pre-treatment (dual stage)	Microfiltration, (45 psi)	20,000 TDS oil field brine	25%, (5)	$1.27
Desalination (single stage)	RO seawater (650)	12,000 TDS oil field brine	3.5% (.28)	$12.55
Pre-treatment (dual stage)	Ultrafiltration (50 psi)	NR	NR	$0.50

a = transmembrane pressure, psi
b= small scale system test on simulated brine. No operating costs determined.

The Table shows information from both pre-treatment and from RO desalination. In addition it contains comparison data from "single stage" and "dual stage" tests. The dual stage tests were conducted with parallel filters in line, taking advantage of flux across filters and relatively low permeate flows.

The NATCO tests were performed in 2004 using produced water from a lease near Crane, Texas. The objective of the tests was to condition produced brine that was to be re-injected into an oil bearing formation. The Ultrafiltration membrane used had an open area cross section of 0.1 micron opening. The tests were successful and the operator is considering a 25,000 bpd facility.

Task 3. Documentation & Technical Transfer

Texas A&M TEES Communications was our partner in this project and served as the spokesman for the project. The project is supported externally by the GWPC and GPRI.
The project has received favorable publicity. In 2003 and 2004 Burnett gave presentations to the American Association of Petroleum Geologists (AAPG), the city Council of San Angelo Texas, the American Membrane Technology Association (AMTA), the City of El Paso Membrane Pre-Treatment Workshop, the United Nations Food and agriculture Organization (FAO), and the Society of Petroleum Engineers.

In addition A&M has been featured in the Schlumberger Technical Journal (2004 1Q), the American Oil and Gas Reporter (March, 2005), and the Saudi Aramco Technology Journal (2003). In 2005, the magazine *Landscapes* will feature desalination as an option for Texas agriculture (*Landscapes* is published by the Texas A&M University System for the Agriculture College and has a circulation in excess of 16,000 copies.)

Burnett has also given technical presentations at four SWC regional technology transfer workshops and participated in the 2004 technology exchange in Oklahoma City sponsored by the Oklahoma Marginal Wells Commission.

Task 4. Identify Reimbursement Mechanisms

We have worked to identify market based mechanisms to encourage those who employ these new operating practices. As an example of the type of incentives that could be employed, the Texas Legislature is creating incentives for those who develop unconventional sources of fresh water resources. The 2005 Texas Legislature is considering two bills proposed by State Senator Armbruster to provide funding for alternative water supply facilities and for desalination of seawater and brackish ground wate[11]. There is to be a tax subsidy available that can offset costs of constructing desalination facilities that supply fresh water to communities in water starved areas of the state. Such measures are a continuation of the type of incentive created by the state of New Mexico that provides a bounty of $1,000 Ac. Ft of water treated and released into the Pecos River watershed.

Section 3

Results of Study

While we do not have long-term operating performance on the systems (goal was 1,000,000 gallons of water processed) we believe that the operating costs and performance of the units have been well characterized and that the process design has been fully proven.

We still anticipate that the new A&M process designs will reduce operating costs of the desalination units significantly. This would show that a marketable resource, fresh water can be recovered from oil field brines, avoiding the expense of water transport to field sites. The expected **operating cost** of the units are expected to be from $0.15 to $0.25 per barrel ($70 to $150 per day for a 20,000 gwpd unit).

Fresh water recovered from the water treatment units can be used to remediate sites that have been spoiled by oil or brine spills offering tremendous potential cost savings. The State of Texas budget in 2002 for oil field cleanup was more than $20,000,000[3]. This money is for cleaning up oilfield sites (more than 600) and to plug abandoned wells (more than 18,000). Improved cleanup techniques and faster remediation offers the promise to save millions of dollars in Texas alone.

Beneficial Use of Desalinated Oil Field Brine

Areas in West Texas with significant oil and gas production (and brine production) will be the most likely candidates for beneficial use of produced water. Municipal use of produced water desalination (PWDS) technology might possibly be a beneficial use of the resource. Distribution and/or storage of desalinated water, either in surface lakes and ponds or in subsurface aquifers, are a significant issue that must be considered when evaluating PWDS economics. Technology is available that allows pre and post-treatment required to assimilate or blend desalinated water into the local water supply system. For example, Odessa's average daily water use the last two years has been 12 million gallons/day in winter and 29.5 million gallons/day in summer, with a peak of 34.9 million gallons used on June 26, 2002. The difference in water use in the summer is predominately landscape irrigation. Corresponding daily brine disposal in Ector, and neighboring Midland, and Winkler Counties Texas in 2002 has been slightly more than 4,000,000 gallons of water per day according to TWDB records, or 25% of the water used on landscape irrigation in the city[12]. Most other areas of Texas reflect the same water usage.

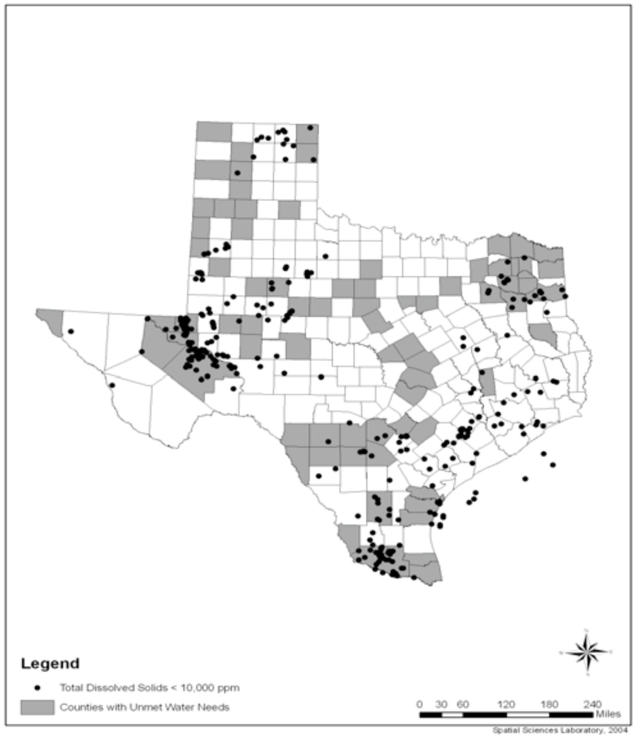


Figure 7 shows the distribution of brackish produced water sites in the USGS database for Texas. The brines are shown with EPA classified counties with unmet water needs[13,14].

Many areas of the state have unmet water needs. Additionally TWDB anticipates a significant increase in demand for fresh water resources in the next 20 years. These socioeconomic factors indicate that should be significant potential for uses of water produced from oil field brine if the fresh water recovered meets the applicable regulations that such usage requires.

Universities have been investigating the potential for rangeland and habitat restoration programs in West Texas, the use of brackish water for growth of crops and the study of salt-tolerant plants[17]. The results of analyses focusing on restoration of rangeland systems may provide a prioritization where habitat enhancement would be most efficient. Of significant interest will be the development of cooperative programs with other environmental agencies and introduction of the technology to determine their opinions on use and acceptance. Hand in hand with this opportunity is the potential to use desalination as a way of enhancing the quality of impaired streams in Texas.

Potable Uses

As mentioned above, the highest level of water treatment is associated with human ingestion. The Texas Commission on Environmental Quality has responsibility for the quality of water discharged into the public sector. A project involving potable use of treated brine produced by oil and/or gas wells would receive extreme scrutiny by the TCEQ. However, if the requirements of the applicable regulations were met, the State would review the information submitted to confirm there were adequate safeguards[15].

The applicable TCEQ Rule pertaining to public drinking water systems is TAC Chapter 290, Section 42(g). This section states that "other" treatment processes will be considered on an individual basis. Based on input from TCEQ staff, a licensed professional engineer must provide "pilot test data or data collected at similar full-scale operations" of the proposed system demonstrating that the system would meet applicable Drinking Water Standards. The pilot test must be representative of the actual operating conditions that can be expected over the course of a year, meaning the test must be done during the time of the year that would place the most strain on the treatment system. Additionally, proof of a one-year manufacturer's performance warrantee or guarantee assuring the plant will produce treated water that meets minimum state and federal drinking water standards is commonly required by the State as a condition of an operating permit.

Therefore, if this water was to be used as an independent potable water source, among other drinking water standards, TDS levels must be reduced to the Environmental Protection Agency's secondary standard of 500 mg/L. Permitting for waters with a TDS greater than 500 mg/L may be available if this water is the only potential potable resource for a community. However, if the high TDS water were to be blended with another public water supply (PWS) and then distributed, the required level of treatment could be less.

Discharge to Supplement In stream Flow

Discharges to surface water designated as Waters of the State must meet Texas Surface Water Quality Standards (TSWQS) as contained[6] in TAC Chapter 307.Without a specific stream or amount of discharge set, it is difficult to outline all necessary regulations one must follow. The permitting process, done through the TCEQ Water Quality Division, is conditional on two key variables, the receiving stream ambient quality and the volume of the discharge. The TSWQS identify individual water quality standards for each stream in the State, and these standards are based on the use category a particular stream is assigned. A discharge, once dilution has occurred, must not hinder the water quality standards set for the receiving stream.

TCEQ Guidance Document RG-194, *Procedures to Implement the Texas Water Quality Standards*, provides a section entitled, "Screening Procedures and Permit Limits for Total Dissolved Solids" states, "Concentrations and relative ratios of dissolved minerals such as chloride and sulfate that compose total dissolved solids (TDS) will be maintained to protect existing and attainable uses". The screening procedure is applied to all domestic dischargers with an average permitted flow of 1 million gallons per day (MGD), all industrial majors, and all industrial minors that discharge process water. The screening procedure is divided into categories based on the type of receiving stream: intermittent stream, perennial stream, intermittent stream within three miles of a perennial stream or intermittent stream with perennial pools, lake, and bay or wide tidal river. The equations used take the following into consideration:

- TDS criterion of the receiving stream (as defined in the TSWQS)
- Harmonic mean flow of the receiving stream
- Effluent flow volume
- Effluent TDS concentration
- Effluent concentration at the edge of the human health mixing zone

For discharges to freshwater, a screening procedure is used to determine whether a total dissolved solids (TDS) permit limit or further study of the receiving water is required. If screening demonstrates elevated levels of TDS, then appropriate permit limits are calculated. The following Figure developed by TWRI outlines potential sites.

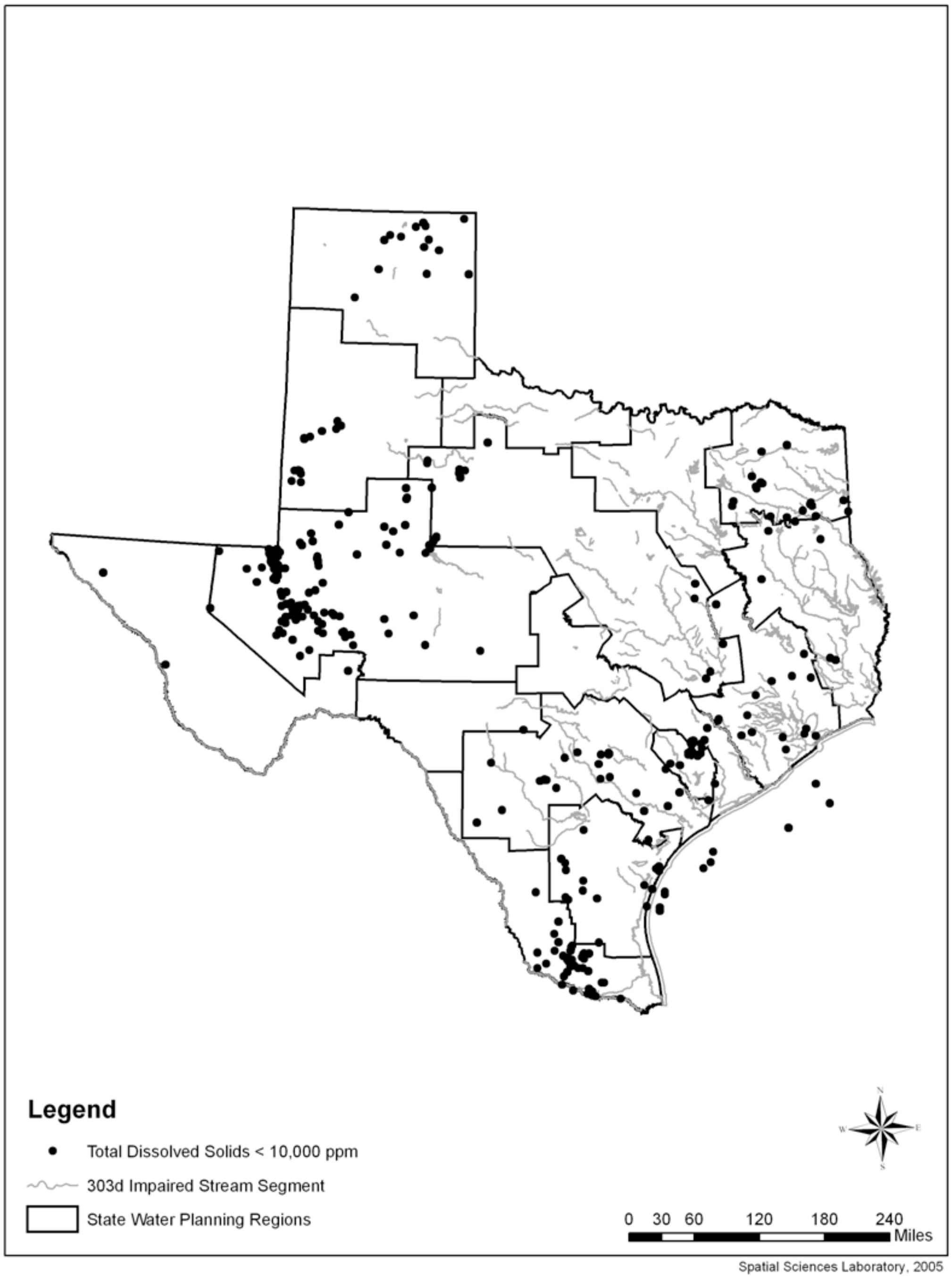


Figure 8 Locations in Texas where brackish produced water production is near streams impacted by poor water quality. The dark outlines are Texas Water Districts.

Livestock Uses

Another potential use of the brine-produced water is livestock drinking water. There are very little, if any, regulations to follow for this potential beneficial use.. If the owner of the livestock is amenable to using a water supply, he is allowed to do so. A typical rule of thumb, though, is a TDS limit of 6,000 mg/L for this purpose. This is the TDS concentration TCEQ employees use when gauging if a particular stream is suitable for livestock use. In many areas of West Texas, surface water supplies approach this level.

Irrigation of Rangelands and Habitat Restoration

Necessary treatment levels of water to be used for crops and grasses irrigation is driven by the salt tolerance of the crop or landscape. The landowner must know the drainage characteristics of his soil, its SAR (Sodium adsorption ratio), and the type of grass or other plants to be sustained. (The sodium adsorption ratio measures the relative proportion of sodium ions in a water sample to those of calcium and magnesium. The SAR is used to predict the sodium hazard of high carbonate waters especially if they contain no residual alkali.)

Care must also be taken to avoid salt buildup if drainage is marginal. Information received from the Texas A&M Soil and Crop Sciences department has provided the following information on salinity tolerance of turf grass:

Table 5. Salt Tolerance of Various Grasses (Potential Uses of Water Produced from Brine)

Common Name	Threshold TDS[1]	50% Growth[2]
Bermuda grass	Less than 960	8,800
Creeping Bentgrass	0 to 1,920	-
Kentucky Bluegrass	0 to 1,920	1,920 to 2,560
Perennial Ryegrass	1,920 to 8,000	6,400 to 8,000
Seashore Papsalum	Less than 960	14,400
St. Augustine grass	Less than 960	18,400

1. TDS level at which the grass begins to slow growth due to salts.
2. TDS level at which growth is slowed to 50% of that in salt free environment.

Additionally, when irrigating with something considered reclaimed water, care must be taken regarding the potential for runoff to Waters of the State. This must be avoided with the use of best management practices.

Aquifer Recharge

Aquifer Storage and Recovery (ASR) refers to the storage or banking of fresh water in aquifers. ASR is a water resources management technique for actively storing water underground for recovery and use when needed (ref xx). "Conjunctive use" and "artificial recharge" are sometimes used interchangeably. Conjunctive use is a combination of practices to make the best use of surface water during wet periods and ground water during dry periods, but does not necessarily imply active water storage practices used in ASR. Artificial recharge (AR) is actively moving water into ground-water systems. AR can be seen as the storage part of aquifer storage and recovery.

ASR offers advantages over surface-water reservoirs in terms of construction costs, environmental effects, evaporative loss of water, water eutrophication, reservoir induced earthquakes, potential for catastrophic failure, and proximity to users. Most ASR projects are associated with large water treatment operations where fresh water can be stored in the aquifer in times of low water demand, to be pumped out in times of high demand. . Currently, there are a number of ASR facilities operating in Florida with more planned.[18,19],

ASR for the fresh water production from oil field brine has not been proposed. Use of treated brine for aquifer recharge could increase groundwater availability. However, if the water is to be stored in a potable aquifer zone, the rule of thumb is that the water must be treated to drinking water standards. One potential attraction for aquifer recharge is that it could be used for water rights transfer from party to party. Such offsets are accepted in the Columbia River Basin in Oregon and Washington where a one-to one- replacement of fresh water is required for permits to be issued for new fresh water usage[20]. In effect, a potential user of the fresh water from the aquifer can provide a "one-for-one" gallon replacement into the aquifer from fresh water injection at another location. The aquifer would necessarily need to be unitized for this eventuality. An analogy is with oil and gas producing properties where unitization of fields is the norm rather than the exception. All of these scenarios would require some form of regulatory reform.

Potential for Saline Water for Oil Field Use

The oil and gas industry uses large amounts of water for daily operations. Brines are used to formulate drilling fluids, kill fluids, cementing fluids, completion fluids, and fracturing fluids. The prime requirement for these systems is that the brines must be consistent in quality and not have any material that might cause compatibility problems. Practically speaking, this means that the brines should be of neutral pH, have minimal hardness and, if iron is present; it must be stabilized in a soluble form.

Since pre-treatment of brine is a major part of the A&M program, we have worked to condition various brines using microfiltration and ultrafiltration to remove contaminants. Field testing at Denton Creek provided a test case. Table 2 showed power usage vs. water treated for saline produced brine. Operating costs (based upon $0.07 per Kwh) have been estimated between $1.27 and $3.24 per 1,000 gallons of brine treated.

We found that this cost of low-pressure membrane treatment to condition brine was a practical option, however the resulting brines are not stable for long periods of time and will require iron chelants. Further work is needed to determine compatibility of such systems in oil field brine uses for other purposes.

As an example of the cost savings, Table 6 shows a worksheet prepared with the assistance of Devon Energy[21]. The Table shows a cost savings of over $38,000 per well if water could be re-used rather transported off-site to a disposal well.

Table 6. Potential for Savings with Use of Treated Brine for Fracturing Operations

Fracturing Operations-Current Practices							
Step No.	Description	Volume		Cost of the step		subtotal cost	
		bbls	gallons	$/bbls			
1	Water Transport to Well	18,000	756,000	$	1.35	$24,300.00	
2	Frac Water Treatment on site	-	-	$	0.01	$0.00	
3	Water to Well 2	-	-	$	1.00	$0.00	
4	Water to Disposal Well	18,000	756,000	$	1.00	$18,000.00	
5	Disposal costs	18,000	756,000	$	0.35	$6,300.00	
				Total costs		**$48,600.00**	
	Demineralization with UF to remove TSS, biofilm, and scaling materials						
		Comparison of Costs		BBls treated =		18,000	**$ Savings per well**
		Existing Practices				$ 48,600	
		Pre-Treatment & Desalination				$ 47,448	$1,152
		Pre-Treatment only				$ 10,044	$38,556

Potential for Use in Waterflooding Operations as Make-up Brine

General Regulatory Requirements Relating to Beneficial Use

The regulations applicable to this type of source water are not clearly defined. According to the Texas Commission on Environmental Quality (TCEQ) staff, this water would be considered an Industrial Reclaimed Water, and would, therefore, be subject to all rules relevant to the use of industrial reclaimed water (Texas Administrative Code, Chapter 210, Subchapter E, and Special Requirements for use of Industrial Reclaimed Water).

Additionally, any proposed use of industrial reclaimed water not considered "on-site" must comply with numerous other general reclaimed water requirements, including the sampling and analysis frequency. For Type I reuse, those uses where human contact is likely, the water must be sampled for applicable parameters, which depend on the applicable use, twice per week. For uses considered Type II, those uses where human contact is unlikely, the water must be sampled for applicable parameters once per week.

Source water quality is of great concern, particularly when the end use will be potable. Any system providing drinking water to more than 25 people must meet restrictions on the amount of pollutants allowed in the drinking water system. Due to the concern regarding contaminants that exist in the source water, as well as potential precipitation, fouling, and scaling of the membranes, a study conducted for the Nueces River Authority suggested source waters high in salt content be tested for 27 different parameters prior to the planning of a treatment facility (HDR, 2000).

Because the rules regarding this type of water source are not clearly defined, regulatory staff suggested that, once a project is defined, an official letter be sent to the State to inquire about all relevant regulations and permits necessary

Barriers to Adoption of Produced Water Desalination

Our program has been well received by industry and the government. In Texas, the Governor and the Texas Water Development Board (TWDB) have been providing leadership for the state in developing desalination programs, including treatment of waste water and oil field brine. However, environmental and regulatory issues related to desalination of produced water in Texas clearly inhibit technology advancement of this resource. Cost reduction advancements in technology are slowed by a lack of a clear “path to market” of new products and processes. It is hoped that this SWC project willo add a different perspective to discussions about water sources for desalination, conveyance issues associated with water transfer, and the demand for the resource if it were to be made available.

Local issues that communities would identify as barriers must be addressed at the local level. Barriers include the perception that desalinated produced water is not pure enough for consumption by humans or livestock and that there might be environmental drawbacks to its use for plants, range, and habitat sustainability. It is suggested however that advanced technology and an improved regulatory climate will increase the likelihood of adoption of PWDS by water use groups in the state.

The Texas A&M program is sponsored by the Stripper Well Consortium (SWC), the Global Petroleum Research Institute (GPRI), and by the Texas Water Resources Institute (TWRI) It is endorsed by the Texas Railroad Commission, the agency responsible for regulating the oil and gas industry in Texas.

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Build and Test a New type of Compressor For Stripper Well Production Application

Final Technical Report

July 1, 2003
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Principal Author: Paul Weatherbee
W&W Vacuum & Compressors, INC.

December 2004

Project No. 2552-WWVC-DOE-1025

BUILD AND TEST A NEW TYPE OF COMPRESSOR FOR STRIPPER WELL PRODUCTION APPLICATION

FINAL TECHNICAL REPORT

JULY 1, 2003
DECEMBER 31, 2004

PAUL WEATHERBEE, PRINCIPAL AUTHOR
W&W VACUUM & COMPRESSORS, INC.

2552-WWVC-DOE-1025

ABSTRACT

The research and development project goal is to evaluate the Weatherbee compressor concept via prototyping and testing in a controlled environment. Specifically:

1. **<u>Task 1</u> of the project requires re-engineering the existing 8.5 inch pump design into a 4.0 inch compressor version with two seal configurations. One configuration features fluid seal and the other features mechanical seal, which had to be designed, for operation with minimal lubrication.**

2. **<u>Task 2</u> of the project requires construction of two prototype compressors in order to establish baseline operating characteristics and performance and to specifically evaluate seal designs. During the performance of this task we designed 3D computer models which were, and will continue to be, extensively utilized.**

3. **<u>Task 3</u> of the project requires bench testing of prototype compressor systems.**

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EXPERIMENTAL

Task 1 and Task 2 discussed in detail in the RESULTS AND DISCUSSIONS section of this report provide extensive information relative to the experimental nature of this project. The experimental aspects of the test bench are discussed below.

The custom compressor test bench described in Task 3 is the cornerstone for compressor experimental testing. Further details of the test bench are as follows:

1. **Heavy steel construction for vibration absorption and for a rigid coupling environment;**
2. **Ten horsepower drive motor;**
3. **Closed loop dry sump lubrication system for both oil intake injection and internal lubrication;**
4. **Intake vacuum monitoring;**
5. **Intake/exhaust temperature monitoring (4 ports);**
6. **Combined exhaust flow rate, including downstream temperatures, pressures and flowrate;**
7. **Custom oil/air separator with oil return line to dry sump system;**
8. **Exhaust pressure monitoring;**
9. **Programmable digital compressor motor control; and**
10. **Heavy duty high misalignment stainless steel drive coupling.**

The test bench will accommodate all current versions of the four inch compressor, as well as future versions up to approximately 5 inches.

Compressor testing is conducted via conventional experimental methods for similar machinery. Specifically, compressor rpm is established in a steady-state environment or via a programmed performance cycle featuring a range of shaft speeds. Intake suction is measured. Similarly, exhaust temperature is measured very near each compressor chamber exhaust port. Type T thermocouples are utilized. Downstream of the exhaust manifold, where both compressor chamber exhaust hose merge, flow is measured with a conventional turbine flowmeter with standard atmosphere compensation. Pressure and temperature is also measured nearby the flowmeter. This apparatus, in total, allows for rapid and repeatable compressor performance characterization.

Finally, as mentioned in Task 3, experimental testing activity to date has considered mechanical survival of prototype components only. There has not been any significant compressor performance characterization, although we are confident that the test apparatus is well designed and prepared, and will allow compressor evaluation upon initiation of our next round of activity.

RESULTS AND DISCUSSIONS

Task 1:

The first activity required selection and qualification of an engineering and manufacturing facility that would work closely with W&W to re-engineer the preexisting 8.5 inch pump, and formalize the new 4.0 inch configurations. This project requires a high quality manufacturer with a strict design and quality control system. Moreover, the selected manufacturer must be capable of maintaining very close dimensional tolerances and be capable of manufacturing complex component geometries. Another essential feature of the selected manufacturer must be their ability to effectively use three-dimensional design software such as SolidWorks.

Over ten different facilities were considered: two in the Dallas-Fort Worth area, one in Eastland, Texas, one in Brownwood, Texas, and six in the Austin area. The selection process included meetings with company owners, engineers, quality control specialists and manufacturing specialists. Business references and experience with similar projects were also considered.

Thereafter, W&W selected Athena Manufacturing, LP, located in Austin, Texas. Not only does Athena have a state-of-the art facility but they are also ISO 9001:2000 compliant and expect registration in December 2004. They have a highly skilled engineering staff, as well as a core group of highly skilled machining experts who are proficient in all phases of modern computer-based machining technology.

Athena's quality management system requires thorough work instructions for every component, followed by dimensional and cosmetic inspection throughout each step of the manufacturing process. Permanent records of such inspections are kept for future reference and traceability. Athena's facility is temperature controlled, and their inspection personnel use extremely accurate three-dimensional measuring equipment. W&W has been more than pleased with the quality of the workmanship provided by Athena.

After selection of the manufacturing facility, W&W, along with Athena engineers, began the engineering process whereby the original 8.5 inch pump mechanical drawings were converted into a three-dimensional computer-aided-design (CAD) electronic format. The engineering software package SolidWorks was selected due to its widespread use and parametric capabilities. SolidWorks CAD models and drawings can be electronically reprocessed for any spherical diameter, and subsequent design changes do not require manual regeneration of every compressor component drawing, resulting in a substantial efficiency gain during the evolution of this family of products. As our R&D efforts progress we will benefit greatly from this initial, time-consuming 3-D CAD model preparation effort.

During this engineering phase of the project, two separate configurations of pump sealing

methodologies were selected, one fluid-based and one mechanical-based. The fluid seal system will require oil injection into the compressor intake stream as well as an internal re-circulating bearing oil system. The mechanical system will feature the same re-circulating oil system, but will feature face, lip and/or gland seals between the vanes and housing, thereby eliminating the need to inject oil into the compressor intake stream.

Specifically, the four compressor locations that we considered sealing are: (1) between the carrier ring and stationary shaft; (2) between the vanes and the housing; (3) between the vanes and the stationary ball; and (4) between the vane-to-vane overlap.

The fluid-based seal system achieves compressor chamber sealing hydrodynamically. A precision controlled lubricator apparatus injects oil into the compressor intake stream, much like a system employed in rotary screw devices. Initial testing during Task 3, described in detail below, proved that without location (1) seals excessive oil from the re-circulating oil system entered the compressor chambers resulting in fluid locking and mechanical damage, therefore the fluid-based seal system will feature location (1) seals similar or identical to the mechanical-based configuration. This seal must be located in the (1) seal area between the carrier ring and stationary shaft. Two different seals, each with a different material, were tried and failed; the details regarding these failures are discussed below.

For both seal configurations, W&W solicited seal design assistance from several seal manufacturing vendors. Specifically, we met with Parker-Hannifin design engineers in both Abilene and Austin to inspect the pump, review the 3-D CAD models and conduct engineering discussions. We had multiple meetings with Boeing engineers in Houston, including detailed evaluation of the 3-D CAD data. We also had multiple meetings in Shiner, Texas and Austin with Boedeker Plastics representatives. Many other prospective seal vendors and consultants were researched and considered. The substantial time consumed with soliciting seal configuration advice and suggestions from recognized industry experts greatly accelerated our compressor seal design cycle, and established a broad knowledge base on which we will rely on heavily going forward.

Several seal designs were identified for potential use in the mechanical-based seal configuration. One is a Parker-Hannifin design. This polymeric seal is molded from a liquid-filled polyurethane and features an energized design to impart continual pressure between the vanes and housing. This seal will be used in locations (2), (3) and (4) listed above. Parker-Hannifin engineers in Houston, Dallas and Salt Lake City participated in this design effort.

Another design for the mechanical-based system was for use in location (1), between the carrier ring and stationary shaft. The location (1) seal is critical in that it must be present to prevent excess oil from getting into the pump. After extensive research and with assistance from both DuPont and Boedeker Plastics engineers, the engineered polymer Radel was selected based on its widespread application in oilfield applications, as well as its low water absorption

and thermal expansion coefficients. As a contingency, we also selected the engineered polymer Delrin (acetal copolymer) for this seal design. Both materials (Radel and Delrin) were used and under test conditions, both failed. Although we were assured that neither of these materials would "swell" when they were put under "load" (heat and oil), they both failed when tested.

W&W has worked with Boeing's Engineers to develop the most recent seal design considered for the mechanical-based system (this is the third seal designed for the (1) location).. This energized type seal is also for use in location (1), and features a spring-loaded carbon composite seal element housed in a stainless steel ring. We believe this configuration has the flexibility to withstand the "load pressures" which will be encountered in seal location (1).

Task 2:

After approval of the compressor design, including the two seal configurations the process of machining and assembling the prototype compressors began. Due to the complexity of many of the components, and the very close dimensional tolerance requirements between moving components, there was a steep learning curve on the shop floor. While this learning curve caused some delays, W&W remained focused on the project requirements.

Each component and subassembly was assembled, checked, adjusted and rechecked numerous times in order to achieve the required component interrelationships. As is the case with all new product development, actual hands-on activities establish the accuracy and suitability of the computer-based design, while simultaneously uncovering design errors and/or shortcomings. For example, one problem we encountered was due to tolerance stack-up in a particular subassembly, which SolidWorks did not predict. Several instances of this nature occurred resulting in component redesign and subsequent remanufacture. The manufacturing process generated a significant collection of nonconforming and/or obsolete pump components, representing a substantial investment of both time and money.

A total of five compressors were built. Compressor housings were manufactured in heat-treated alloy steel, cast iron, and acrylic polyurethane. Compressor vanes and shafts were manufactured in heat-treated alloy steel and 17-4 PH stainless. A wide variety of bearing types and assembly configurations were evaluated. Painstaking efforts were undertaken to achieve the closest dimensional tolerances of the shaft/vane subassembly without sacrificing future manufacturability.

We currently have compressors running smoothly, after overcoming some initial problems always associated with resizing and implementing a new design; i.e., vibration, knocking and metal-to-metal contact.

<u>Task 3:</u>

Task 2 and Task 3 occurred simultaneously – as soon as a complete compressor was manufactured it was tested. Thereafter, after the next sequence of design and/or manufacturing revisions were complete another round of testing transpired. In the near future, and when the compressor design stabilizes, much more formalized bench and field testing will occur, especially with seal development.

Each compressor was bench tested using a custom test bench. The test bench features a 10.0 horsepower synchronous AC motor with a programmable digital controller. This arrangement allows specification of precise RPM and/or shaft power thereby allowing highly repeatable compressor input conditions. The test bench also features a self-contained re-circulating oil system for use with both the fluid and mechanical compressor seal configurations.

Needless to say, the bench testing revealed a substantial amount of information, often times in the form of a post-failure analysis. Initially, the bench testing served simply as a mechanism to conduct reliability testing. We simply need to achieve prolonged compressor operation, regardless of performance, without suffering a mechanical failure. Thereafter, as we established reliability via design and manufacturing process evolution, we began focusing on performance and data collection.

Due to the time and costs associated with successfully manufacturing an operational prototype while simultaneously designing and developing two compressor seal configurations, we have depleted Phase I funding, and the continuation of Task 3 will shift to Phase II funding. Specifically, we expect the Boeing face seals (location 1) to be successful, thereby allowing finalization of the fluid-based seal configuration, as well as subsequent implementation of the Parker vane seals to finalize the mechanical-based seal system.

<u>Confidential and Proprietary Information Regarding Task 3:</u>

During Task 3 activities, it became apparent that the compressor housing port (suction and discharge) design was not optimized. Specifically, the original design caused re-compressing due to an inordinate port overlap inherent to the timing of the compressor. This caused substantial extra work and associated heat generation, while substantially degrading the output pressure capability. It was determined that we needed to both reshape and relocate the ports and by using the 3D Computer Model were able to accomplish this task.

We approached this redesign activity with a goal of achieving a 3:1 compression ratio. This design change has been completed, and also features the capability to further throttle the compressor with simple intake port inserts which should allow inexpensive compressor configuration for any specific wellhead condition. We expect this ability to easily configure

a compressor for any desired compression ratio by simply changing an insert will represent a giant leap for this family of products by providing a wonderful level of versatility.

Upon initiation of Phase II funding all Task 3 testing activities will be based on this new port design.

Financial Report

Under this grant, W&W Vacuum & Compressors, Inc. received an award of $100,000.00 for Building and Testing a New Type of Compressor for Stripper Well Production Application", with a cost share commitment from W&W of $50,000.00. W&W requested reimbursement from the Stripper Well Consortium a total of $100,000 and contributed (cash and in-kind) a total of $81,025.00.

Conclusion:

At the end of Task 1 activity, the design of the four inch unit for stripper well use was completed. It was identified early on that the design of the seals between the rotating and stationary components would be a driver in successful operation of this unit. Therefore, considerable effort was spent meeting and working with various seal OEM's. Most notably, the services of Parker Hannifin were employed to provide an energized contacting polymer seal design to be used between the vanes and the stationary components. It was also recommended that a simple o-ring type seal between the carrier ring and the center ball stationary shaft be used.

The goal in Task 2 was to draw the compressor in 3-D modeling software; i.e., Solidworks. Once the compressor was successfully "modeled" on the computer it was possible to look at each component part. From Solidworks the files were then transferred to a computer program called Mastercam - Version 9 prior to machining the parts. Since the design of the compressor is so innovative, it has been virtually impossible in the past to demonstrate to engineers and others exactly how the device works. The computer modeling done in Task 2 enabled W&W to "animate" the workings of the compressor and has proven to be invaluable as it makes the compressor dynamics more easily understood.

The unit testing performed in Task 3 identified shortcomings in both the seal system and the port geometry. First, the energized polymer seal was difficult to install between the vanes and the center ball stationary shaft and it was not possible to inspect the installation to insure a proper fit. In addition, the seal system used between the vanes and stationary components did not cover enough of the voids to prevent significant leakage between the compression and suction chambers. This greatly impacted the unit efficiency of the mechanical seal configuration. New design concepts are being investigated to achieve a more comprehensive and reliable seal between the vanes and the stationary components. The failure of the o-ring type seal at the carrier ring impacted both unit configurations; i.e., the fluid seal and the mechanical seal. However, a new seal technology has already been designed and manufactured that is expected to be much more reliable and will be applied to both configurations. As mentioned previously, performance concerns about the intake and discharge ports were also identified and addressed in this task. The time invested in working through the seal and port designs prevented the collection of comprehensive pump/compressor performance data. When these efficiency losses are eliminated, realistic performance measurement will be possible.

Even though it was not possible to gather comprehensive test data; W&W was able to bench test and to sustain 15" to 24" of hg vacuum. In short bench test runs compression output pressures ranging between 20 and 80 lbs. were achieved. These pressures were not, however, sustainable, as slippage in the seal areas generated too much heat. This issue will be further refined as our Research and Development continues.

APPENDIX F:

TASK 5: APPLICATIONS OF LASERS, MICROWAVES, AND ACOUSTICS TO STRIPPER WELLS AND OIL/ GAS APPLICATIONS

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DISCLAIMER

ABSTRACT

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EXECUTIVE SUMMARY

This report investigates lasers, microwaves and acoustics technologies and the potential for these applications in the oil/gas industry as well as other industries outside the oil and gas fields. It explores the problems peculiar to the oil and gas field, market potential, and timing. This report is a summary of the “crossover application” potentials for the technologies and the current state of the art with respect to the understanding the technology and the efforts that must be brought to bear to adapt the technology to the oil and gas field applications.

Lasers: The rapid advancement of laser technology has several fields looking to adopt its viable applications and incorporate this technology instead of conventional techniques. The oil and gas fields are likewise looking to adopt the laser technology in several areas. High power lasers have proven to be successful in penetrating rocks. The daunting task of delivering the laser power to the rocks at the downhole situation still remains.

Advancements in fiber optics have shown that a substantial amount of high-powered laser energy can be transported via fiber optics. With present norms and limitations, the laser technology can be used for regulating formation damage and stimulating oil and gas productions. Another laser application is perforating production casing at the well bore location instead of using shaped charges.

Microwaves: Microwave heating differs from conventional heating in that the heat is generated internally within the material instead of originating from external sources. Recent innovations in the area of microwave processing have been developed. This makes it possible to heat both small and large shapes very rapidly, uniformly, and efficiently. Due to the highly efficient energy transfer and rapid heating rates, the material can be processed in a few minutes. Among the most prominent are those on tungsten carbide (WC) based cutters (universally used in drill bits). This has opened new avenues in developing drill bits for geothermal, oil, gas, mining, excavation, and other industries. This not only improves the performance of the systems, but also reduces the overall cost of drilling.

Acoustics: The third investigation is the potential of acoustic technology to advance oil and natural gas technology. There is a need for the development of a theoretical/mechanistic framework that explains reported laboratory and field results in the area of acoustic stimulation. Although many of the building blocks for global acoustic prediction are present, there is still much work required to model these processes with sufficient accuracy.

EXPERIMENTAL

This project was not a project using experimental methods; rather it was a review of the current state of laser, microwave and acoustic technologies and a. summary of the “crossover application” potentials. It investigates materials and publications on the current state of the art with respect to the understanding the technology and the efforts that must be brought to bear to adapt the technology to the oil and gas field applications.

APPENDIX A

L A S E R S

ABSTRACT

In a much unsophisticated sense, a laser can be regarded as a special kind of flashlight. Like any other powered lighting device, energy goes in and light comes out. The difference between the emitted lights from each is worth discussing and researching. The general notion that lasers are far more powerful than any flashlight is erroneous. There are many lasers that are much weaker than even the smallest flashlight. It is not power that defines the difference between laser and normal light.

The uniqueness of laser light lies in its detail. Its characteristics properties like coherency, monochromatic nature, collimated etc. that make it so special. Since the inception of lasers there has been a rapid recognition of its scientific and practical significance. This entirely new source of light packed with power was a radiation that was vastly superior in precision and could be manipulated for as required or necessary. The creation, the research, the development, and the application if this special light involves the knowledge and experience from several other fields: classical and quantum physics, chemistry, electronics and engineering. However, many of the important ideas in this field are probably known now and the basic processes well understood. The laser brought about a revolution in optical technology and spectroscopy, and had far reaching influence in various fields of science. The unprecedented boom in areas of laser research regarded it as a solution waiting for a problem.

The discovery of different kinds of lasers was only one of the achievements. Scientists delved into the underlying physics and precisely analyzed the properties of lasers and related them to the parameters of lasers. A continuous sequence of more and more powerful laser inventions followed which brought new varieties of applications and solutions with them. The inception of new applications required further research to enhance the efficiency of lasers or maybe invention of newer ones.

Lasers now come in all sizes – from tiny diode lasers small enough to fit in the eye of a needle to huge military lasers and research lasers that can fill a 3-storey building. They are now sold for both commercial and non-commercial purposes. The success story lies in the fact that laser is a tool that is able to be an extremely precise technique. The selection of the most appropriate type of work can be carried out in a very accurate and more importantly, controlled manner. Lasers can now be seen in fields of telecommunications, medicine, graphics and non-intrusive measurement techniques, electronics, grocery stores, military and many more areas. There seems to be no end to the ingenious way a narrow beam of light can be put into use. For once you might see it yielding colorful patterns from a tiny gadget, or then u can expect one to drill through rocks like a butter knife. On one hand it can weld metal sheets and on the other it can be carefully used to assist eye surgeries.

The next few chapters give an insight into the science of lasers. After a brief yet broad introduction to lasers and the underlying physics of the process, an extensive study of laser applications in various fields is presented. Related research areas are mentioned, analyzed and recommendations are proposed. A set of convincing and credible upcoming ideas are revealed as a topic for future outlook which may help in later researches and laser investigations. A vast collection of literature survey pertaining to the discussed topics is listed at the end of the section.

LIST OF FIGURES

CHAPTER 1.1

INTRODUCTION

The word "laser" is an acronym for **L**ight **A**mplification by **S**timulated **E**mission of **R**adiation. That expression means that the light is formed by stimulating a material's electrons to give out the laser light or radiation. Atoms and molecules exist at two energy states: high and low. Those atoms at low levels can be excited to higher levels, usually by heat. They give off light when they return to a lower level from the higher ones (Fig. 1.1).

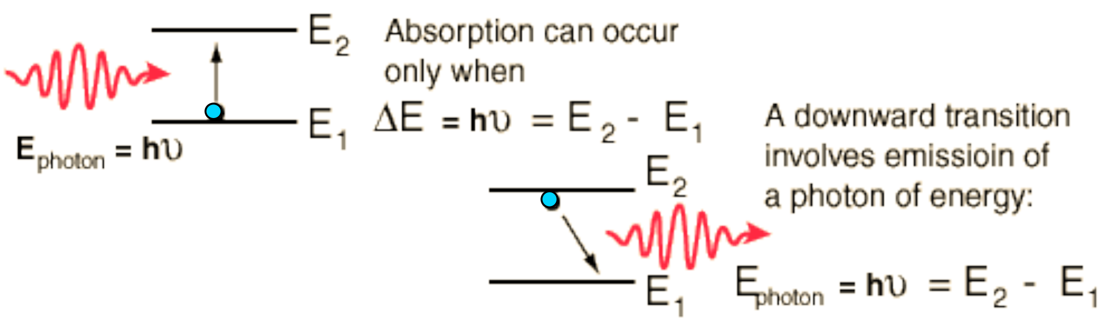


Fig.1.1: *Higher Energy levels possess atoms at higher energy states*

$$E = h\upsilon \tag{1.1}$$

Where,

E = Energy of photon in joules

υ = Frequency of the photon in hertz.

h = Planck's constant = 6.625×10^{-34} joule-seconds

The laser uses a process called **stimulated emission** to amplify light waves. One method of amplification of an electromagnetic beam is to produce additional waves that travel in step with that beam. A substance normally gives off light by spontaneous emission. One of the electrons of an atom absorbs energy. While it possesses this energy, the atom is in an excited state. If the electron gives off this excess energy (in the form of electromagnetic radiation such as light) with no outside impetus, spontaneous emission has occurred.

If a wave emitted by one excited atom strikes another, it stimulates the second atom to emit energy in the form of a second wave that travels parallel to and in step with the first wave. This stimulated emission results in amplification of the first wave. If however the atom is not isolated, other effects may occur. Photons of the same energy as the energy of the upper level may use their energy to move an electron from the lower level to the upper one. This is known as absorption, as the photon is destroyed in the process.

If a photon of the correct energy passes an atom with its electron in the upper level, then it may cause the electron to fall to the lower level. This is what is called **stimulated emission** and is very different from spontaneous emission. In the spontaneous process the photon may travel in any direction and be emitted at any time. Stimulated emission, however, causes the emitted photon to travel in the identical direction to the passing photon and at the same time hence causing the amplification.

If the two waves strike other excited atoms, a large coherent beam builds up. But if they strike unexcited atoms, they are simply absorbed, and the amplification is then lost. In the case of normal matter on Earth, the great majority of atoms are not excited. As more than the usual number of atoms become excited, the probability increases that stimulated emission rather than absorption will take place. In a laser stimulated emission is the biggest effect.

Normally atoms and molecules emit light at more or less random times and in random directions and phases. All light created in normal light sources, such as bulbs, candles, neon tubes and even the sun is generated in this way. The wavelength of a beam can determine its energy. Hence, we can consider that if there is energy stored in the atom and light of the correct wavelength passes close by something else can happen: The atom emits light that is totally synchronous with the passing light. This means that the passing light has been amplified, which is necessary for the oscillation taking place between the mirrors in a laser. In Fig. 1.2, notice how the red ray of light gets thicker (amplified).

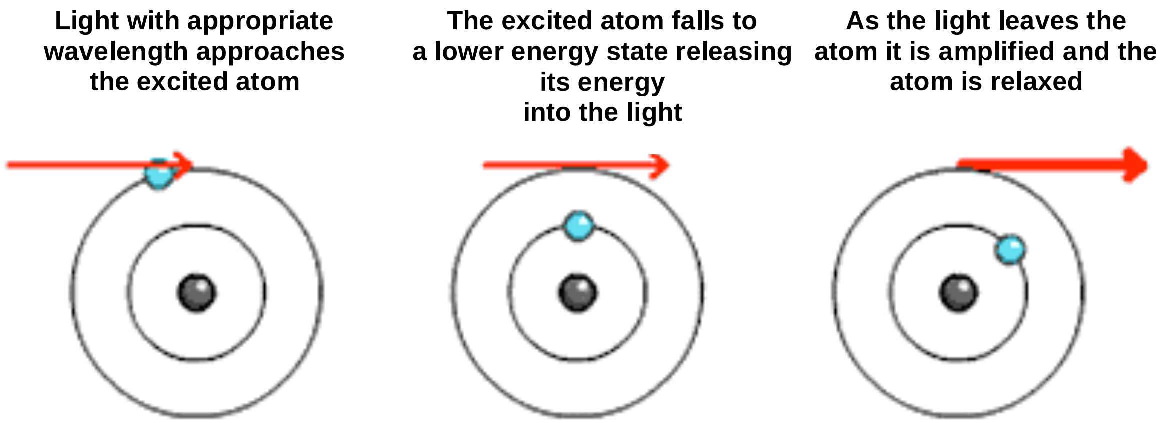


Fig.1.2: *Atoms release their energy into the passing light which causes them to fall to the lower energy state*

Simply stated, a laser is a device that creates and amplifies a narrow, intense single-frequency, single-wavelength beam of parallel light. Atoms emit radiation; when they are excited, neon atoms in a neon sign, for instance, emit light. Normally, they radiate their light in random directions at random times. The result is incoherent light; a technical term for photons, the smallest unit for light hurtling in every direction. Laser is a device that would generate coherent light that would be synchronized at a single frequency and that would travel in a precise direction. To constitute this, we have to find the right atoms, and most importantly create an environment in which the atoms all cooperate, meaning that they would give up their light at the right time and move in the same direction

With the elements of a basic working laser we can propose how a setup of the Laser (Fig. 1.3) would look like as it was discovered by Dr. Theodore "Ted" Maiman—the world's first working laser—which represented a major breakthrough in the field of applied physics.

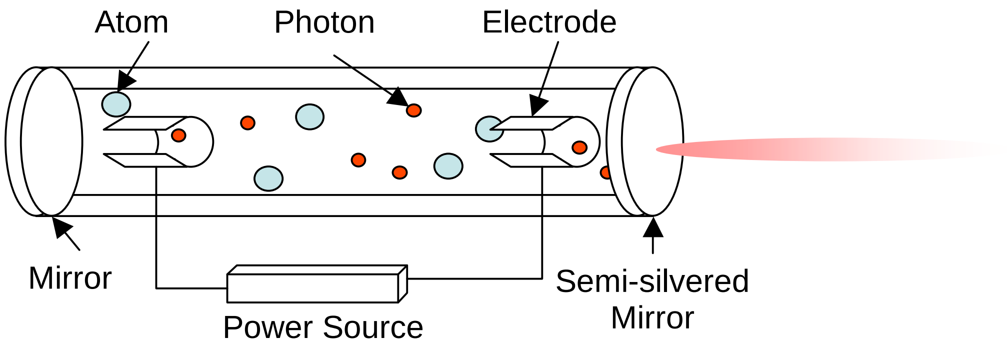


Fig.1.3: *Basic setup of a working Laser*

Although there are many types of lasers, all have certain essential features. In a laser, the lasing medium is "pumped" to get the atoms into an excited state. Typically, very intense flashes of light or electrical discharges pump the lasing medium and create a large collection of excited-state atoms (atoms with higher-energy electrons). It is necessary to have a large collection of atoms in the excited state for the laser to operate efficiently. In general, the atoms are excited to a level that is two or three levels above the ground state. This increases the degree of population inversion. As explained in the following chapters, the population inversion is the number of atoms in the excited state versus the number in ground state.

Once the lasing medium is pumped (excited with a power source), it contains a collection of atoms with some electrons sitting in excited levels. The excited electrons have energies greater than the more relaxed electrons. Just as the electron absorbed some amount of energy to reach this excited level, it can also release this energy. This emitted energy comes in the form of photons (light energy). The photon emitted has a very specific wavelength (color) that depends on the state of the electron's energy when the photon is released. Two identical atoms with electrons in identical states will release photons with identical wavelengths.

The illustrations below (Fig.1.4 & 1.5) give a basic idea of the working of a laser both at the instrument level and the atomic level. The working and operation of a laser will be discussed in later chapters. The next chapter will discuss the events which eventually led to this amazing discovery.

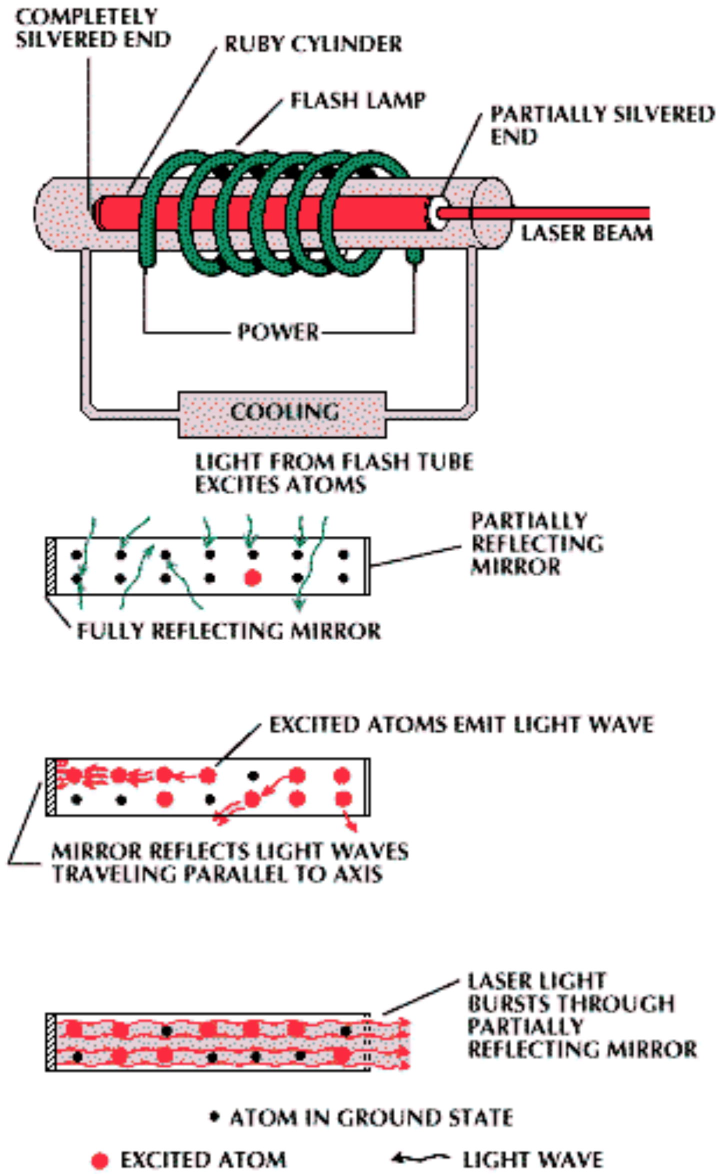


Fig.1.4: *An illustration of a normal functioning of a Laser*

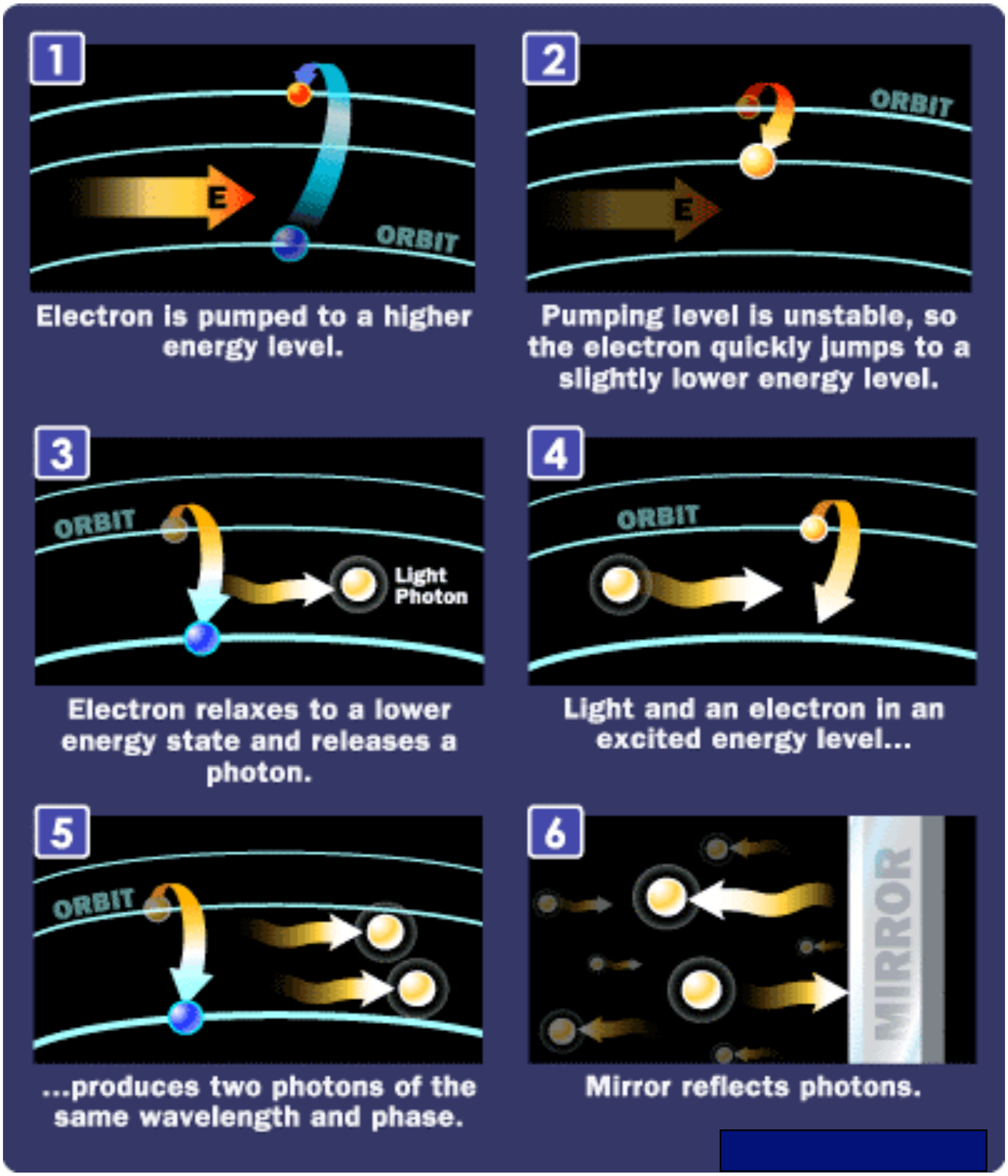


Fig.1.5: *Basic atomic level illustration of the working of a laser*[1.8]

CHAPTER 1.2
HISTORY

The idea of using concentrated beams of light as a power source was not considered by most people as an especially promising idea. The laser was something of an afterthought, a potentially interesting elaboration of an instrument designed to amplify the strength of microwaves.

The ubiquity of microwave technology – it has applications in radio, television, radar, meteorology, satellite communications and distance measuring – has robbed it of much of its mystery. But in fact, the notion that microwaves could be useful for detecting enemy aircrafts or printing documents or heating a cheese burger never even entered scientists' minds they first began to investigate the phenomenon. Their interest in the subject was almost entirely theoretical. Microwaves, they believed, could be harnessed as an important tool to study the properties of matter. Microwaves are short, high frequency radio waves lying roughly between very-high-frequency (infrared) waves and conventional radio waves (1mm to 30cm). Microwaves, it turns out, have the capacity to stimulate atoms, allowing scientists to investigate matter in different states.

In 1916 Albert Einstein (1879-1955) had shown theoretically that atoms stimulated by radiation could emit, as well as absorb, radiation[1.1]. By the late 1930s, most microwave technology relied on vacuum tubes capable of emitting microwaves as short as a few millimeters. If however the wavelengths could be made even shorter, scientists reasoned, then they could produce stronger radiation. This would provide a better understanding of how the action of molecules and atoms could be used to control radiation. But this could not be accomplished so long as the technology was limited to vacuum tubes. Some other devices would need to be invented to generate waves short enough to achieve the effect researchers wanted. Charles H. Townes (Fig. 1.6), a South Carolina Physicist was among the researchers who finally succeeded in developing a working laser.

Fig.1.6: *Charles Townes*

Fig.1.7: *Arthur Schawlow*

When Townes set out to develop a more efficient device for generating shorter microwave radiation, he only intended it to be an aid in the study of molecular structures. Townes concentrated his efforts on microwaves spectroscopy and how to achieve shorter wavelengths. His focus was a device that would generate microwaves of great intensity, i.e., the shorter the wave, the stronger it is. In 1951, Townes hit upon the idea of producing this energy not by electronic circuits, which had been the focus of his earlier efforts, but rather by manipulating the molecules themselves. It was the ammonia molecule which is a very strong absorber and interacts strongly with wavelengths that caught Townes attention. He hypothesized that he would be able to get the ammonia molecules “excited” by pumping energy into them through heat or electricity, after which he would expose them to a weak beam of microwaves. Molecules excited in this way would then be impelled to emit their own energy in the form of microwaves, which would bombard other molecules in turn, causing them to give up their energy. By using the very feeble incoming microwaves generated by ammonia molecules, he hoped to initiate a cascade of chemical processes that would produce a highly amplified beam of radiation.

In December 1953, Townes succeeded in constructing a device that would produce strong microwaves in any direction. They called the process microwave amplification by stimulated emission of radiation, which become known more popularly as the MASER. The MASER quickly found many applications for its ability to send strong waves in any direction. The first masers used a static electrical charge to discard low-energy molecules of ammonia gas which excited the first batch of molecules of ammonia gas which excited the first batch of molecules inside a cavity; as those molecules returned to a lower energy level they released microwave radiation. This radiation, reflecting inside the cavity, stimulated additional molecules to radiate energy. This process amplified, or intensified, the microwave radiation emitted by the device.

In spite of the success of the MASER, Townes still wasn't satisfied. If the maser could do so well at producing microwave amplification, he thought, why couldn't a similar instrument do the same with a beam of light? In grappling with the question, he sought the help of another physicist who shared Townes fascination with microwave spectroscopy, Arthur Schawlow (Fig. 1.7). Schawlow and Townes wondered if the process could operate the same way that the maser did. Energy would be generated from molecules and atoms picking out certain ones with excess energy and allowing the waves to interact with them and drain the energy out of them. In the masers it would be amplified microwaves; in this case the result would be amplified light. Light waves were also different from microwaves in that they were much shorter to begin with-about twenty thousandths of an inch, in contrast to microwaves which are about one hundredth of an inch or a millimeter in length.

But how to create a device to generate these intensified light waves? That was where Schawlow came in. His idea was to arrange a set of mirrors, positioning each one at the end of a cavity, and then bouncing the light back and forth. In this way it would be possible to eliminate any amplification of any beams bouncing in the other directions, in effect ensuring that the light would have only a single frequency. Schawlow and Townes were both excited by the possibilities, and by 1957, they began working out the principles of a device that could emit high-intensity light beams.

Townes called his idea for a new device an optical maser. It wasn't long before Townes and Schawlow came up with a technical paper titled –"Infrared rays and Optical Masers", which was published in the Dec. 1958 Physical review, the Journal of American Physical

Society. There still remained the question of whether a real laser could be made to work. Confirmation of Townes & Schawlow's paper, a mad scramble began, with scientists and from academia to industry contending to be the first to develop a practical laser. It was however Gordon Gould, the coiner of the term "laser" - light amplification by stimulated emission of radiation-who claimed to have invented the first practical laser, if anything, even stronger than Townes, in 1960. Eventually he seemed to have forgotten to file for a patent.

Fig.1.8: *The first successful working laser, constructed by Dr. Ted Maiman in 1960. Courtesy: HRL Laboratories, LLC.*

Fig.1.9: *Dr. Ted Maiman, constructor of the first working laser. Courtesy: HRL Laboratories, LLC.*

Soon after the new invention, Peter Sorokin[1.2] and Mirek Stevenson developed the first 4-level laser in 1960. This laser made from uranium doped calcium fluoride was theoretically proposed to provide continuous output although in solid state but failed to do so. By the end of 1960, Ali Javan[1.2], William Bennet, and Donald Herriot made the first gas laser using helium and neon. These He-Ne lasers became the dominant laser type for the next 20 years until cheap semiconductor lasers took over in the 80s. The He-Ne lasers are still used in applications such as reading UPC product codes, surveying equipment etc. The He-Ne laser was first laser to emit a continuous beam. Also, the lasing action could be initiated by an electric discharge rather than the intense discharge of photons from a flash lamp. In 1964, C. Kumar N. Patel[1.2] began working with carbon dioxide and carbon monoxide lasers which he mixed with nitrogen, helium and water to fine tune the laser properties and eventually ended up with the first high powered gas lasers. The same year Earl Bell discovered the ion laser when he placed mercury ions in helium to create lasing action. The mercury ion laser led to the invention of the argon-ion laser which was developed by William Bridges and other metal vapor lasers.

The laser technology suddenly saw a rapid development and many laser developments followed. The new lasers started using chemical reactions instead of electric currents to generate a lasing effect, using rapid cooling through expansion to cause excitation, using dyes as a medium to tune the laser across a range of wavelengths, and using p-n junctions in semiconductors or a free electron medium to create lasing effects. Quickly after their inception the utility of lasers were realized and their conceived uses skyrocketed. A few years after 1964, however, excitement about lasers began to subside. Although new uses had been conceived for them, some of the projected applications were proving difficult to achieve and many lasers were proving difficult to make. For instance, there was little success in developing a continuous, room-temperature semiconductor laser for computing purposes. Laser power also seemed limited, disillusioning the U.S. government in its potential military applications. Lasers were dubbed "a solution looking for a problem." The first uses of lasers consisted more or less of replacing less efficient light sources, i.e. xenon arc lamps in photo-coagulators and mercury arcs in interferometers. Laser research slowly continued and increased its breadth. There were a variety of improvements in laser design which increased laser lifetime, focused beam width, improved continuity of output, regulated and shortened pulse duration, etc. Anthony DeMaria's[1.2] development of mode-locked neodymium-doped glass lasers with thousands of megawatts peak power and picosecond durations, improved laser performance to standards necessary for high-speed photography and scientific applications such as the study of physical and chemical phenomena.

Lasers began to emerge as a prospective application in Communications. The fact that the amount of coherent information that an electromagnetic wave can carry if proportional to its frequency and that optical light has frequencies 109 times larger than radio waves and 105 times larger than microwaves deemed Lasers an ideal solution to the existing congestive communication technology. There had to be many other technologies to be invented which would make laser communication practical. The first invention was the discovery in 1970 by Charles Kao[1.3] and George Hockham[1.3] that glass fibers could transmit laser light efficiently. Also in 1970, a method was invented to improve the p-n junctions in semiconductors which reduced the current densities needed for semiconductor lasing. Now lasers were tunable to a sufficient level to make them reasonable and advantageous for spectroscopic uses.

As lasers possess high intensity and narrow bandwidths, they have solved the longstanding problems in IR spectroscopy like poor detector sensitivity and low source intensity. Applications of Lasers can be found in UV-Visual Spectroscopy and also in fluorescence spectroscopy. It also led to the development of Raman Effect or the so called Raman Spectroscopy. Lasers have also opened up the realm of nonlinear spectroscopy. The field of Chemistry realized lasers which then led to become a whole new chapter under photochemistry called – Laser-induced chemistry. In spectroscopic methods, the laser induces no chemical change in the sample - it simply causes short-lived changes in the electron populations of different energy levels. The powerful intensity of lasers can be used to overcome energetic barriers to reaction, since it is electronic energies which are involved in the formation and rupture of chemical bonds. The ability to pulse laser radiation, however, creates a means for inducing and monitoring ultrafast photochemical reactions. It is possible to identify short-lived intermediate species in solution with lasers that have ever-decreasing pulse duration. There has even been some progress in monitoring the rotational and steric action as well as electron transfer rates of species in solution using picosecond and femtosecond laser techniques.

As we can realize that the history of laser lies on a short timeline and is yet so dynamic in evolution, there is no doubt that there will be a rapid rise in the development and research in this field as applied to newer fields and sciences. The potential behind this technology has more to add into any phase of life.

CHAPTER 1.3

PHYSICS

If you have ever shined a flashlight at night, you can see that its beam spreads out, thus limiting its effectiveness. Although the reflector around the light bulb sends the light in a parallel beam, the wave nature of light causes it to spread out. Light is really an electromagnetic wave. Each wave has brightness and color, and vibrates at a certain angle, so-called polarization.

In a light bulb filament, light is sent from various parts in short bursts of energy. These packets of waves randomly come off the filament, such that the light beam is an incoherent mixture of all these bursts of energy. Ordinary light sources operate in such a way that many excited molecules or atoms emit light independently of one another as well as in many different colors, that is, different wavelengths. Hence ordinary light is incoherent and not of a single color.

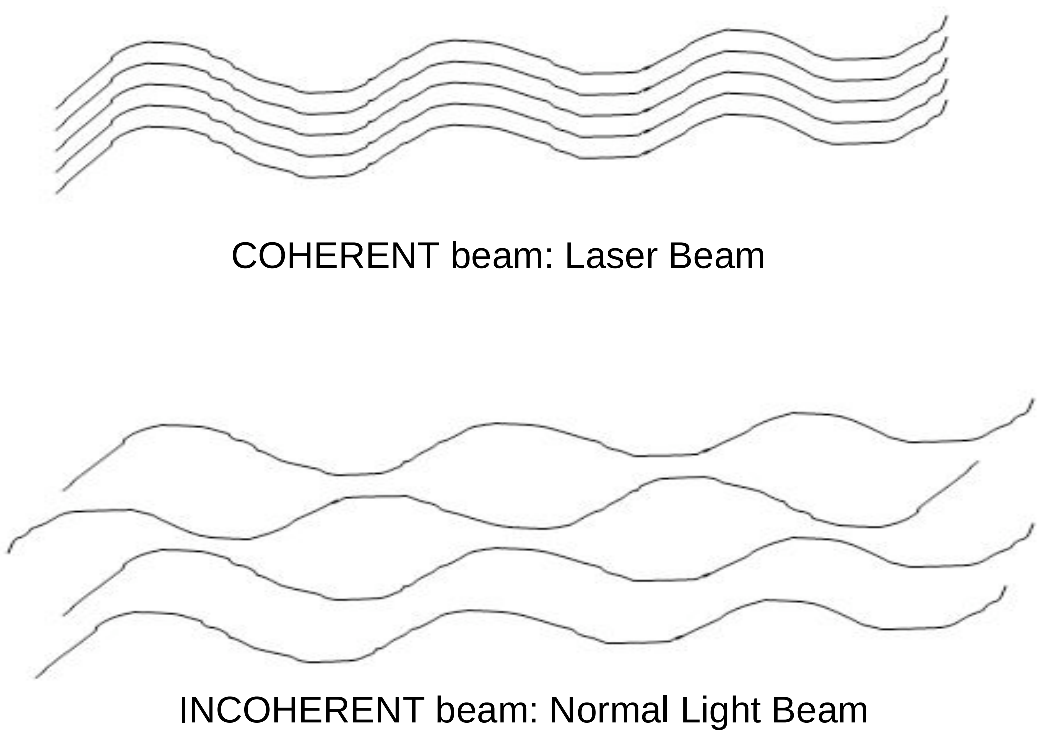


Fig.1.10: *The difference in travel pattern of a coherent and an incoherent beam*

Coherent Light: To produce coherent light, the electrons in the atoms of a Laser medium (gas, for example) are first pumped or energized to an excited state by an external energy source. The external energy is in the form of photons or packets of light. Excited by these external photons, the photons within the laser chamber emit energy-a process which we discussed as stimulated emission. The photons emitted form the laser travel in tandem with the stimulating photons-they are operating at the same frequency. As the photons move back and forth in the chamber between two parallel, silvered mirrors (Fig. 1.11), they trigger additional stimulated emissions. As these stimulated emissions multiply, the result is coherent light, which is single frequency, single color-single wavelength. This intense, directional light finally exits the chamber through one of the mirrors, which is only partially silvered for that purpose.

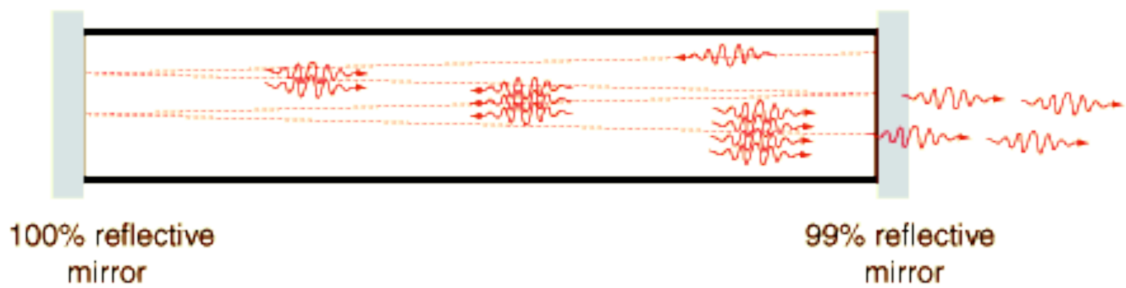


Fig.1.11: *A set of mirrors create a coherent atmosphere*[1.4]

Monochromatic light: All common light sources emit light of many different wavelengths. White light contains all, or most, of the colors of the visible spectrum. Being Monochromatic is a unique property of laser light, meaning that it consists of light of almost a single wavelength. Perfectly monochromatic light cannot be produced even by a laser, but laser light is many times more monochromatic than the light from any other source. In some applications, special techniques are employed to further narrow the range of wavelengths contained in the laser output and, thus, to increase the monochromatic character.

As we have seen how we actually manage to end up with a coherent monochromatic light, however, there were several technical and theoretical boundaries it had to realize, like the second law of thermodynamics. The law which is based on the concept of entropy-measure of how close the system is to equilibrium- in short states that disorder of an isolated system can never decrease. Hence, molecules cannot generate more than certain amount of energy. The second law poses an additional condition on thermodynamic processes. It is not enough to conserve energy and thus obey the first law. Energy has a price. In a closed system where no change is possible and where equilibrium has reached, it would not be possible to produce energy from nothing. Bouncing light back and forth inside a cavity in an attempt to generate higher states of energy sounds like an unfeasible fact.

The simple way justifying the true fact of laser can be explained by the statement that the Second Law of Thermodynamics assumes *thermal equilibrium.* In the case of Lasers we are working with light and not heat. Hence we don’t necessarily have to assume thermal equilibrium.

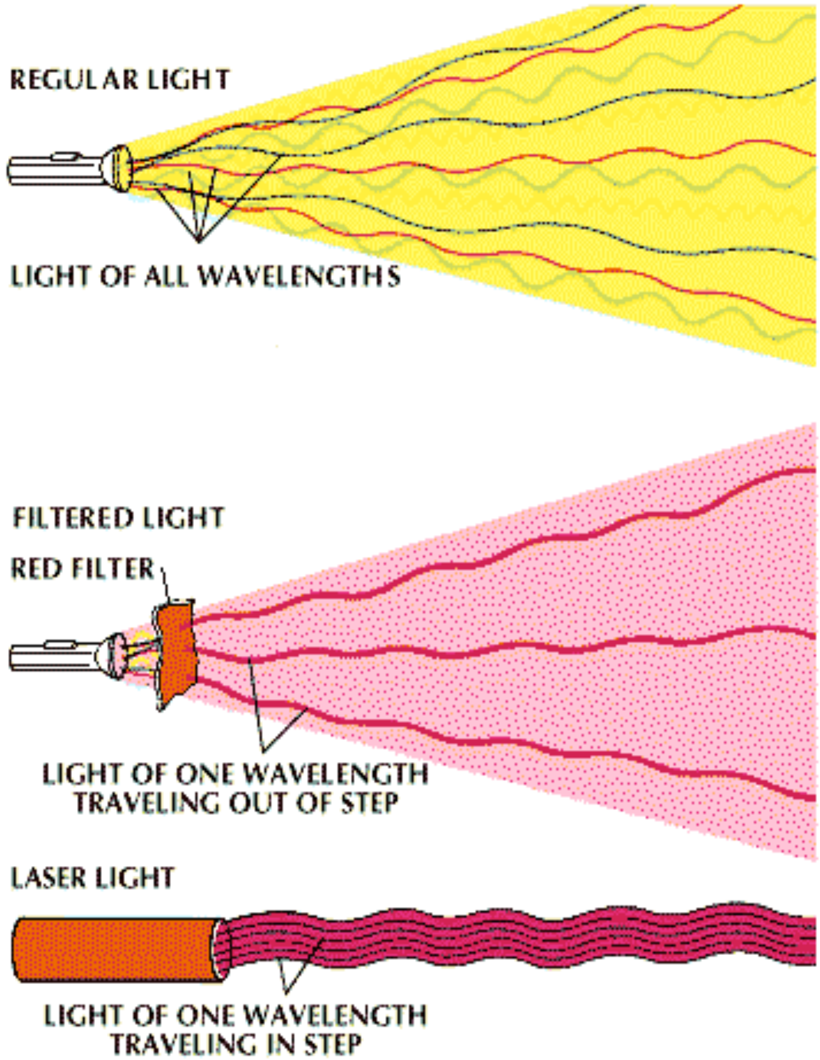


Fig.1.12: *Monochromatic light has as single wavelength. Laser light is monochromatic light which is also coherent*

Collimation: This is another property of lasers which symbolizes parallel light from a laser. The light from a typical laser emerges in an extremely thin beam with very little divergence. Another way of saying this is that the beam is highly "collimated". An ordinary laboratory helium-neon laser can be swept around the room and the red spot on the back wall seems about the same size at that on a nearby wall.

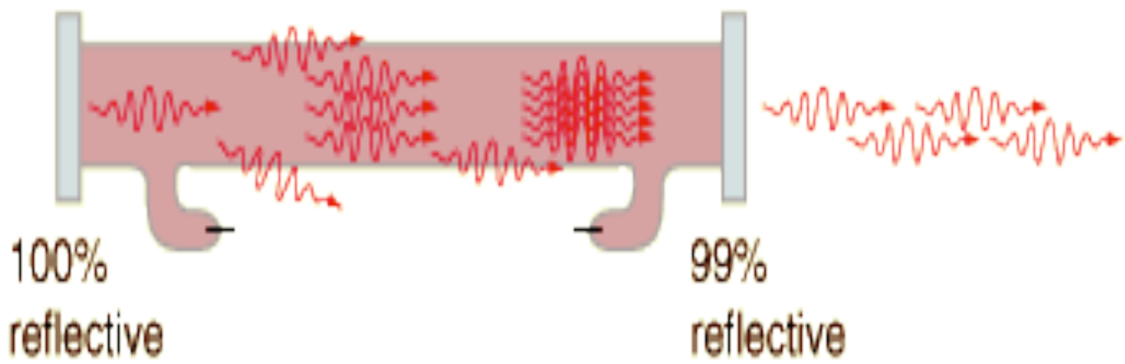


Fig.1.13: A *parallel set up of mirrors clusters parallel beams. The non reflective surface eliminates the beams that are out of step*[1.4]

The high degree of collimation arises from the fact that the cavity of the laser has a very carefully placed parallel front and back mirrors which constrain the final laser beam to a path which is perpendicular to those mirrors. The back mirror is made almost perfectly reflecting while the front mirror is about 99% reflecting, letting out about 1% of the beam. This 1% is the output beam which you see. But the light has passed back and forth between the mirrors many times in order to gain intensity by the stimulated emission of more photons at the same wavelength. If the light is the slightest bit off axis, it will be lost from the beam.

The highly collimated nature of the laser beam contributes both to its danger and to its usefulness. You should never look directly into a laser beam as it can cause instant damage to the retina. On the other hand, this capacity for sharp focusing contributes to the both the medical and the industrial applications of the laser. In medicine it is used as a sharp scalpel and in industry as a fast, powerful and computer-controllable cutting tool.

Population Inversion: The achievement of a significant population inversion in atomic or molecular energy states is a precondition for laser action. Electrons will normally reside in the lowest available energy state. They can be elevated to excited states by absorption, but no significant collection of electrons can be accumulated by absorption alone since both spontaneous emission and stimulated emissions will bring them back down.

A population inversion cannot be achieved with just two levels because the probability for absorption and for spontaneous emission is exactly the same, as shown by Einstein. The lifetime of a typical excited state is about 10^{-8} seconds, so in practical terms, the electrons drop back down by photon emission about as fast as you can pump them up to the upper level. The case of the helium-neon laser illustrates one of the ways of achieving the necessary population inversion.

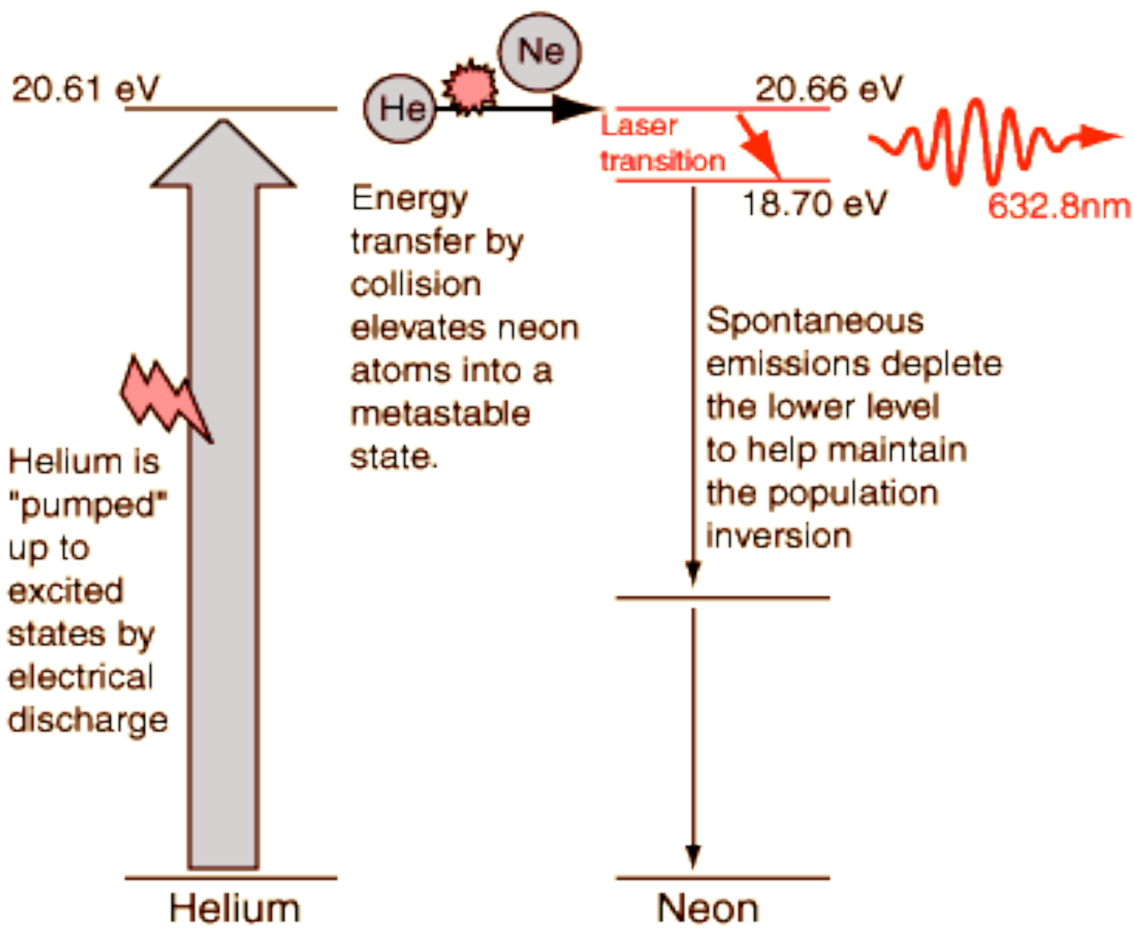


Fig.1.14: *Illustration of Population Inversion*[1.4]

Beam diameter and Intensity: The diameter of an electromagnetic beam, along any specified line that intersects the beam axis and lies in any specified plane normal to the beam axis is the distance between the two diametrically opposite points at which the irradiance is a specified fraction, *e.g.*, ½ or 1/ϵ, of the beam's peak irradiance. Beam diameter is usually used to characterize electromagnetic beams in the optical regime, and occasionally in the microwave regime, *i.e.*, cases in which the aperture from which the beam emerges is very large with respect to the wavelength. Beam diameter usually refers to a beam of circular cross section, but not necessarily so. A beam may, for example, have an elliptical cross section, in which case the orientation of the beam diameter must be specified, *e.g.*, with respect to the major or minor axis of the elliptical cross section.

The cross-section of the laser beam has what we usually call a Gaussian profile, which means that the intensity gradually declines as the radius increases, as shown below. This means that it is hard to define an exact radius, but by convention we have chosen to define the radius of the beam (w) as the radius at the point where the intensity has decreased by a factor of e^2 (=7.389) from the maximum value at the center of the beam. About 94% of the energy is within this radius, and so it is a good way of measuring the area over which the energy is spread. However, this is not a good way to come to a conclusion about the size that an opening or lens should have to let the beam pass, since you get diffraction in the lens even if it is outside of ‘w’ (Fig. 1.15). The most common thing to do is to set the radius of the opening or lens to twice as much as ‘w’; this means that the beam will be practically uninfluenced by diffraction.

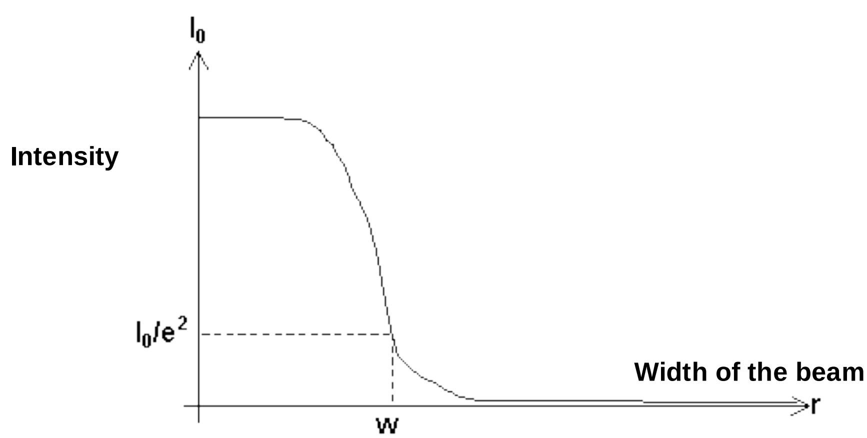


Fig.1.15: *Change of Intensity with laser beam diameter*[1.5]

When you talk about the divergence of the beam, what you mean is the increase of ‘w’ per unit length from the laser, measured in mrad. In reality, this only applies at a longer distance from the laser.

There are two kinds of high power research lasers, **pulsed** and **continuous:**

Pulsed lasers operate for very short periods usually for much less than one second. They can produce extremely high peak powers (energy divided by pulse duration) but only for a very short period of time. Many pulsed lasers have very low average powers (total energy produced in one second of operation)

There are two common methods for pulsing. The most important is the Q-switching method, which simply means that you stop the laser from lasing during a short time (about 100µs), by simply putting something in the way of the beam in the cavity. The result of this is that when the blocking is removed, the beam will grow to very high intensity during a few laps (which takes 2-3 ns). This very intense beam will totally empty level 2 of electrons, since stimulated emission is proportional to the intensity. All of the energy stored in the atoms will be turned into light in very short time. Thereafter, about 20% of this energy will leak out every lap. Thus you have a pulse that grows in intensity for 2-5 ns, and the decline during 10-50 ns. The maximum power in a pulse usually is about 10,000 times the power of the same laser without pulsing. The average power will thus only be a little lower, despite the fact that the laser is kept from lasing most of the time.

Another phenomenon, using interference between the modes is called mode locking, and gives pulses with a length of 10-100ps

Continuous lasers operate continuously for periods exceeding one second. The familiar laser pointer is one example. These lasers usually have a relatively high average power and are often classified as military lasers. Furthermore, the light of a laser is often pulsed in order to be easier for a detector to recognize it in a noisy, with a pulse repetition frequency (PRF) of about 1 kHz; PRF tells the number of pulses per second.

The parameters required to characterize a laser pulse are length, repetition rate, and shape, in addition to energy or average power. These are conventionally both controlled and monitored by modulating the output of high voltage power supply for the laser rather than monitoring the actual laser beam, although this is feasible using photodiode techniques.

The duration of the pulse T depends on what mechanism is used to make the pulses; one of the most common, Q-switching gives pulses of about 20ns. This means that the maximum power[1.5] of the laser can be calculated to be:

$$Power_{\max imum} = \frac{MeanPower}{PRF \times T} \tag{1.2}$$

Where,

PRF =Pulse Repetition Frequency

T =Duration of pulse

From the maximum and mean powers, you can get the corresponding intensity by dividing by the area of the spot.

Wavelength[1.6]**:** The distance between adjacent peaks in a series of periodic waves produced as an effect of stimulated emission is characterized as the wavelength of the laser. As we may have to manipulate the lasing medium to arrive at the required wavelength it is important to know what determines the wavelength of a Laser.

Why are helium-neon (HeNe) lasers red, argon ion lasers green and blue, and CO_2 lasers IR? There is no way to provide a complete answer in a brief discussion but it is possible to outline some of the requirements for laser output to be possible at a particular wavelength.

Consider the lasing medium, such as the 7:1 mixture of helium and neon used in a HeNe laser. If the gas mixture is excited by an electrical discharge, it will produce a bright line spectrum. Each of the colored lines represents a particular energy level transition in helium or neon; the combined mixture will differ slightly. One might think that the brightest and thus strongest spectral lines are the most likely to result in laser action. This is not necessarily the case. For the HeNe case, none of the lines in the helium spectra contribute to the production of coherent light directly - the helium is used only to excite the neon atoms because a set of their upper energy levels match and electrical excitation of the He atoms with subsequent coupling of the energy to the Ne is much more effective than exciting the Ne atoms directly. And, even in the case of neon, only a few of the spectral lines are useful for a laser. In fact, for the red HeNe laser, the one that is important resulting in an output at 632.8 nm is quite weak compared too many of the others.

In order for a laser to lase, the round-trip Laser Resonator Gain (LRG) must start out being greater than 1 (see the section: Resonator Gain and Losses). Oscillations will then build up until non-linearities and finite pumping input bring LRG down to exactly 1. Where LRG starts out being less than 1, at best a weak pulse of light will be emitted as oscillations die out.

The fundamental characteristics of the laser determine whether the LRG greater than 1 condition will be met: A population inversion must exist between the pair of energy levels for that wavelength (photon energy). This is the condition for stimulated emission. The mirrors must be highly reflective at that wavelength and be properly aligned and of the proper curvature (or flat) to result in a stable resonator so that oscillations can build up in the cavity. For a CW laser, pumping energy input must exceed energy used in the lasing process and intermediate energy levels must not get 'clogged up'. The following are among the physical aspects of a laser that can be used to select the lasing wavelength. These are what laser engineers' play with to produce the required wavelength:

- *Composition of the lasing medium itself*: For the HeNe example, the actual gas mixture and pressure may affect the relative strength of the spectral lines to some extent. Obviously, another gas mixture entirely will result in totally different possible lasing wavelengths - or none at all.

- *Mirror coatings*: The dielectric mirrors used in lasers reflect best over a narrow band of wavelengths. This may be controlled very precisely during their manufacture. In fact, this is probably the most important parameter used to select the color of 'other color' HeNe lasers. In addition to the common red HeNe laser, there are also yellow, orange, and green types (as well as those output at IR wavelengths) and the discharge seen inside the tubes for these looks identical to that of the red ones. However, the mirror coatings are quite different

- *Intra-cavity prism or grating*: Since a prism or grating diffracts different color light at different angles, such an element can be set up to result in the mirrors being aligned properly for only a single wavelength to select one of several possible output colors. This may be adjustable. Argon and krypton ion lasers often have a line selecting prism at the HR (High Reflector - non-output) end.

- *Magnets in various locations*: For gas lasers in particular, magnets may be used to affect the relative strength of various energy level transitions through a process called Zeeman splitting. One use is to suppress IR lines in favor of visible ones in long HeNe lasers.

Some lasers - notably argon, krypton, and mixed gas ('white light') ion lasers are capable of multiline operation where several different wavelengths are output simultaneously. For these lasers, the gain must be greater than 1 at all the desired wavelengths. Among other things, this means that the mirrors must be coated to have high reflectivity over the entire range of interest and the excitation must be able to maintain a population inversion for all the corresponding energy level transitions without the strongest one overwhelming all the others.

Resonator Gain and Losses[1.6]**:** Laser Resonator Gain (LRG) is a measure of how much the light intensity increases due to stimulated emission after one round trip through the resonator (i.e., starting from the OC, through the lasing medium, reflected off the HR, back through the lasing medium, ending up at the OC again). Laser Medium Gain (LMG) is just the increase in light intensity due to stimulated emission from one end of the lasing medium to the other. There will be lasing if LRG which is the combination of LMG and all losses, including those due to the useful output beam, is greater than 1. The output power will build up until losses due to non-linearities in the lasing process and finite pumping input bring LRG down to exactly 1 (or the laser blows up). Output power will decrease and eventually die out if LRG is less than 1. In addition to the output beam, losses arise from imperfect mirrors (absorption at the OC and non-total reflection at the HR), reflections and absorption at the Brewster windows (if any), absorption and scatter in the lasing medium, to name a few.

A typical HeNe laser may have a LMG of only 1.01 to 1.05 depending on its length (1 to 5 percent). All optics must be as near to perfection as possible to get anything out of a short tube.

Laser System Efficiency and Laser Life[1.6]**:** Laser efficiency is simply how much coherent light is produced per watt of input power. This could be all the way from the wall plug (which takes into account power supply losses) or just with respect to the actual input to the laser medium (e.g., DC power to the tube or optical power from the flash lamp).

Laser life could also mean the time until the output decays gradually to some percentage (e.g., 50 percent) of the original or specified power level, or how long they will remain at or above the rated power. As above, this will also likely be a strong function of how hard it is driven. This is a common way of characterizing diode lasers and diode pumped solid state lasers. A laser diode may have a specified life of 10,000 hours to the half-power point. Gas lasers often produce much more than rated power when new and it is common for the life to be determined by how long its output takes to drop below rated power.

CHAPTER 1.4

BASIC COMPONENTS & OPERATION

There are 4 functional elements that are necessary in lasers to produce coherent light by stimulated emission of radiation[1.7]. The figure below (Fig. 1.16) illustrates the four functional elements.

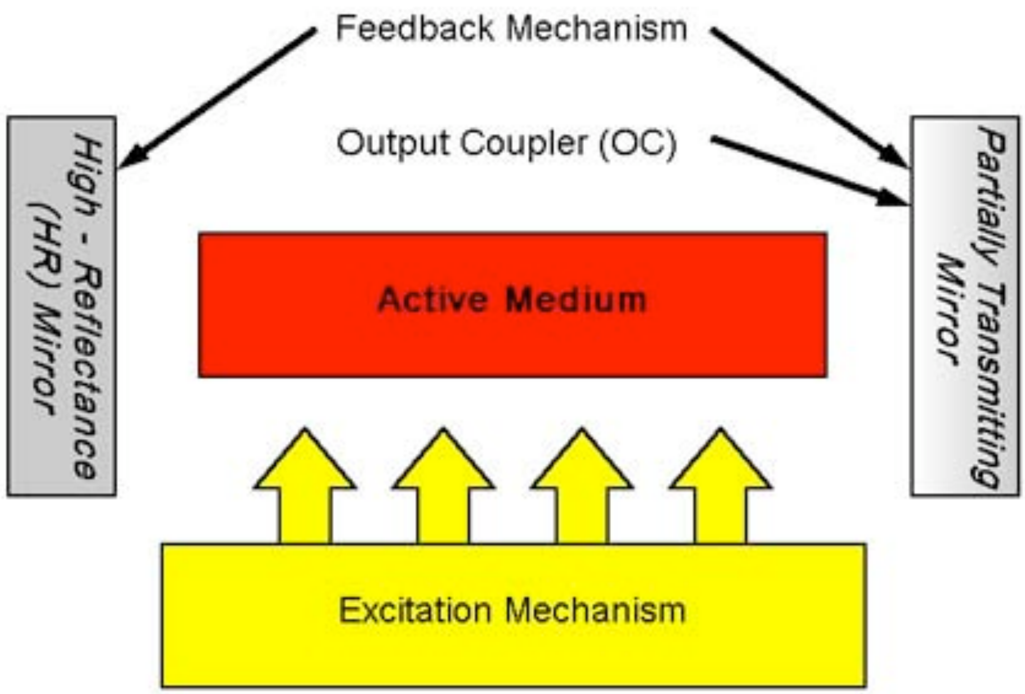


Fig.1.16: *The 4 functional elements of a laser*[1.7]

The **active medium** is a collection of atoms or molecules that can be excited to a state of inverted population; that is, where more atoms or molecules are in an excited state than in some lower energy state. The two states chosen for the lasing transition must possess certain characteristics. First, atoms must remain in the upper lasing level for a relatively long time to provide more emitted photons by stimulated emission than by spontaneous emission. Second, there must be an effective method of "pumping" atoms from the highly-populated ground state into the upper lasing state in order to increase the population of the higher energy level over the population in the lower energy level. An increase in population of the lower energy level to a number above that in the high energy level will negate the population inversion and thereby prevent the amplifications of emitted light by stimulated emission. In other words, as atoms move from the upper energy level to the lower energy level, more photons will be lost by spontaneous emission—giving off randomly directed, out-of-phase light—than gained due to the process of stimulated emission.

The active medium of a laser can be thought of as an optical amplifier. A beam of coherent light entering one end of the active medium is amplified through stimulated emission until a coherent beam of increased intensity leaves the other end of the active medium. Thus, the active medium provides optical gain in the laser. The active medium may be a gas, a liquid, a solid material, or a junction between two slabs of semiconductor materials.

The **excitation mechanism** is a source of energy that excites, or "pumps," the atoms in the active medium from a lower to a higher energy state in order to create a population inversion. In gas lasers and semiconductor lasers, the excitation mechanism usually consists of an electrical-current flow through the active medium. Solid and liquid lasers most often employ optical pumps; for example, in a ruby laser, the chromium atoms inside the ruby crystal may be pumped into an excited state by means of a powerful burst of light from a flash lamp containing xenon gas.

The **feedback mechanism** returns a portion of the coherent light originally produced in the active medium back to the active medium for further amplification by stimulated emission. The amount of coherent light produced by stimulated emission depends upon both the degree of population inversion and the strength of the stimulating signal. The feedback mechanism usually consists of two mirrors--one at each end of the active medium--aligned in such a manner that they reflect the coherent light back and forth through the active medium.

The **output coupler** allows a portion of the laser light contained between the two mirrors to leave the laser in the form of a beam. One of the mirrors of the feedback mechanism allows some light to be transmitted through it at the laser wavelength. The fraction of the coherent light allowed to escape varies greatly from one laser to another; from less than one percent for some helium-neon lasers to more than 80 percent for many solid-state lasers.

In order to understand the way a laser works, we start with a simple example:
Connect a speaker to an amplifier, and a microphone to the input of the amplifier, and set the amplifier to amplify 10,000 times. If you now approach the speaker with the microphone, the speaker will start producing a high-pitched, not very pleasant sound. This is known as oscillation. The reason of it is that the microphone picks up more than 1/10000 of the sound, say 1/8000. Any sound or noise will then be amplified 1.25 times, which means that the sound will grow in intensity. Of course, this will not keep on happening, but after a while the intensity will stop increasing, and we will have a constant level of sound (noise).To do the same thing with light, we should then need two things: An amplifier (amplifying a certain ray of light) and a **feedback-mechanism.**

There are five ways in which light can interact with matter. Let us consider an atom with two interesting levels of energy. With interesting, we mean that there are levels closer to the nucleus that don't participate in creating light, and there are empty levels farther from the nucleus - we want to be somewhere between these. The outmost level full with electrons, we call level 1, and the innermost of the empty (or half empty), we call level 2. It is when the electron is moved between these levels that light is created or absorbed. The difference in energy between the two levels tells us which wavelengths can participate in creating the light.

Absorption happens when light with the "right" wavelength comes close enough to an atom (molecule). The energy of the light is used to carry the electron to the higher level of energy. This ends the story for the photon (light-particle), and the energy is stored in the atom. This energy can now be used to produce heat as it falls back to level 1, or it can be used to emit a new photon. The probability of this happening depends on the intensity of light & the number of electrons on the lower level (N_1). (N2 – number of electrons on level 2)

Spontaneous emission occurs when the electron has been carried to level 2. Here, it waits for a while (between 1ns and several seconds), but as time passes, the probability of the electron "falling" to level 1 increases. As it falls, the stored energy is released as light. This happens at an arbitrary time and in an arbitrary direction. However, if light of the right wavelength passes the atom while the electron is still on the higher level of energy, it will make the electron fall. The light emitted will have the same direction, wavelength and phase as the bypassing light. This is what we had defined as *stimulated emission*, and is as we see a process of amplification. The probability of stimulated emission differs from the probability of absorption only in that you count the electrons on the upper level.

The fourth process means that light of the wrong wavelength passes. The light and the atom do a little "handshake" to see if they are fit for each other; this takes a few femtoseconds. When they realize that they are not, the light just keeps going, as if nothing had happened.

The last phenomenon uses three levels of energy. The light passing (with slightly higher energy than in the last cases) is absorbed, and the energy carries the electron to level three. Here it stays for a very short period of time, and then falls to level two. When this happens, infrared light is emitted; this is often absorbed and turned into heat in the material. The electron the proceeds to fall from level two to level one, and emits light of a longer wavelength (with less energy) than the light employed to carry the electron.

This phenomenon is called fluorescence (Fig. 1.17) and is used e.g. in optic whitewash, and in the color of the vests worn by road workers.

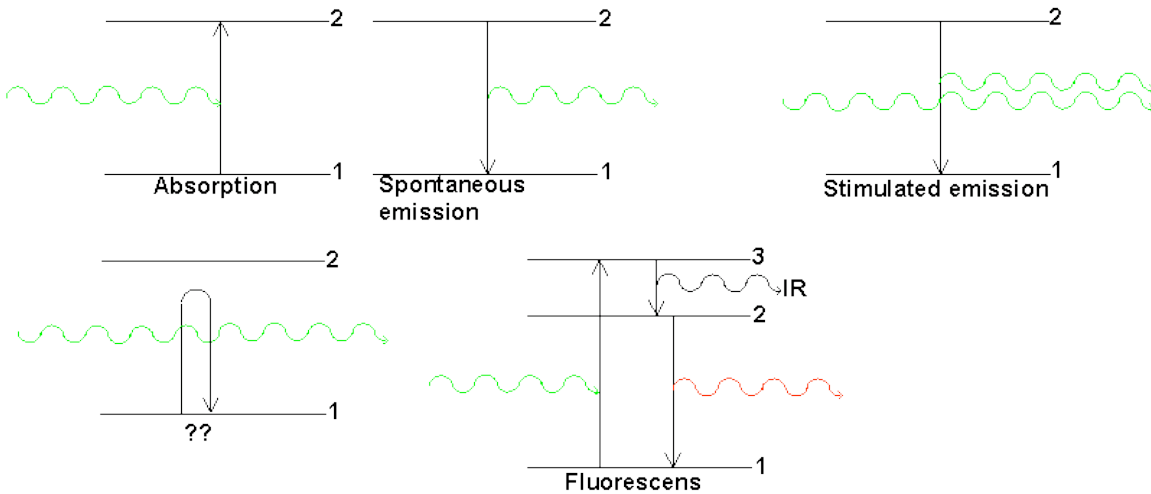


Fig.1.17: *Atomic level observations of each phenomenon*[1.7]

Now, we have the amplification process: *Stimulated emission*. All we have to do now, is make the emission greater that the absorption. Unfortunately, nature once again refuses to be simple; in all natural situations, N_1 is greater than N_2, which means that there is more absorption than (stimulated) emission.

Could simply putting up a lamp with the right wavelength solve this problem? No. This would give more electrons on level two, but the more alike in numbers they get to the ones on level one; the more the probabilities for stimulated emission and absorption approach each other. When these two equal, the probabilities will also equal, and the material will have become transparent. But what if we tried a system with a third level?

If we use a three-level system (such as ruby) and use a wavelength suitable for absorbing between levels one and three (green light), the electrons will then be carried to this level (this is known as pumping the medium). If now the "mean time of waiting" (spontaneous lifetime) is short, the electrons will quickly fall to level two, where the mean time is long in ruby (this is one of the reasons the first laser was of ruby). If the green lamp is powerful enough, the electrons will almost be on level two, which is what we want.

This solved the N_1=N_2-problem, since we are now pumping to a different level from that on which we want the electrons to be. In this way, we can create an inverted population if we have more electrons "out moving" than we have on level one (where they all strive to go). This puts up great demands on the intensity of the pump-lamp, and makes the three-level laser is of an "all-or-nothing" kind. If it lasers, it lasers with such power that the material cannot give off the heat produced, nor is there any lamp able to produce sufficient amount of pump-light for a longer period of time. This means that three-level lasers are often pulsed, and slightly unstable due to the great demands on the pumping.

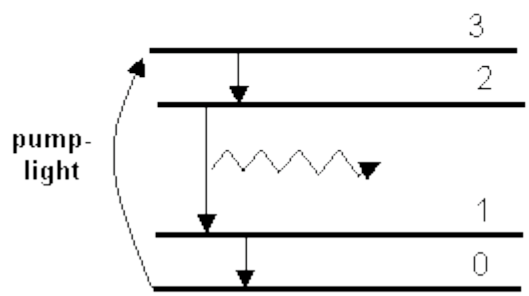


Fig.1.18: *A three level laser*

One solution to this problem is to use a four-level system, a system where the lower level of the emission is **not** the outmost of the populated, but the innermost of the empty. This means that only some of the electrons need to be excited (carried away from their natural position, level 0 in this case) Lasers of this kind can be made to give a continuous beam, with practically as low power as you want. Most modern lasers are four-level.

Now, that we have solved the first problem; amplification, the next one is to get feedback.

This one is much simpler: Two mirrors with a reflectance(R) of 1, gives 100% feedback. If we let on of these mirrors have a reflectance of .8 (a transmittance of .2) this means that we will have oscillation if our medium, with the right pumping, gives amplification greater than 1.25

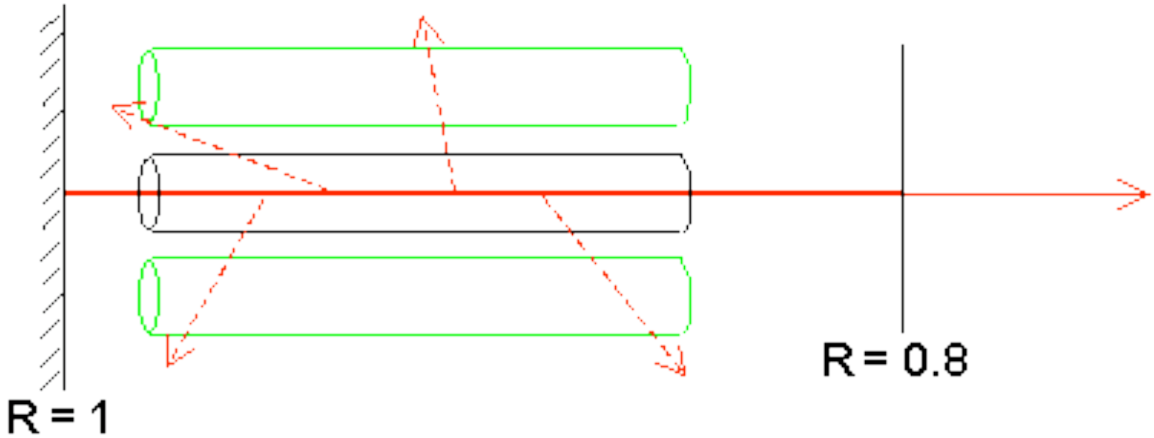


Fig.1.19: *Spontaneous emission and amplification in direction*[1.7]

When the laser is pumped (pump-lamps in green), light will be created by spontaneous emission in all directions from the laser-rod (red dashed lines). Sooner or later, one of these will be sent in the right direction, and be reflected at the mirrors (and amplified in-between). Only this direction will produce oscillation, and a beam **(red bold line)** will be reflected back and forth, growing in energy by a factor given by the amplification times the feedback of every "lap". After a while, the intensity between the mirrors will be so high that the amplification decreases to 1/the feedback, and we have a stable situation. Each lap, 20% of the light passes the right mirror; these 20% are replaced with energy from the stimulated emission. These 20% are our laser beam – thin red emerging line.

CHAPTER 1.5
APPLICATIONS

1.5.1 Industrial lasers

One of the earliest uses of Lasers found it in Industrial and Manufacturing fields[1.9]. Lately, there have been a wide range of lasers being tried & tested to be compatible with the jobs and processes they are required to take on. There have been certain lasers that have proved to be of great value to this field. Among a few are that are compact, reliable and highly stable are:

- Helium-Neon Lasers
- Nd-YAG Lasers
- Semiconductor Lasers
- Noble Gas Ion Lasers
- CO_2 Laser

1.5.1.1 Primary Industrial Applications

- *Machining*: The applications in this area include cutting, drilling & scribing etc. This area was one of the first ones that experimented with the then new technology of Lasers. Among the first major uses (around 1970) was for materials processing in the electronics industry to trim thick film resistors and to scribe silicon devices. Applications like cutting sheets of plywood, cloth and plastic followed. The aerospace industry accepted it and applied for accurate and high-speed laser cutting using CO_2 laser. Cutting of non-metals was fairly adjusted by switching to inert gas lasers. Drilling required much powerful and high density lasers. Industrialists developed stronger & much focused beams to fulfill their job requirements.

- *Engraving*: With the development of more compact and precisely controlled Lasers, engraving using this technology has become a trivial task. Multiple industries utilize this technique in minute arts and crafts, detailed sculpturing jobs, and other printing purposes.

- *Welding*: It was the microelectronics industry that first considered a possibility of utilizing lasers for welding. The aerospace industry & the Vehicle manufacture industry use Laser welding for their mass production. Its potential for high speed and continuous throughout capabilities makes it so compatible with large scale production processes.

- *Heat Treatment*: Laser can be exploited for heating, melting, cladding, alloying shocking or glazing. Transformation hardening, induction hardening fusion of surfaces and modification of surfaces are some other uses of laser heat treatment. Many of these techniques are yet at a preliminary stage and are waiting to emerge in the commercial field soon.

Useful commercial laser developments towards the industry were widely found in the Proceedings of the LAE, Russia, 1996 [1.10]:

- Micromachining with DUV Lasers
- Pulsed Laser radiation for multiple spot welding
- Computer simulation for Laser Beam welding
- Visualization of Laser treatment processes of materials
- Enhanced strength provision for Laser-soldered joints
- Laser setup for flat optical components fabrication

Many more developments in relevant applications can be studied from other proceedings of the SPIE (L.A.E). One of the most important among these applications was **laser welding** which turned the welding process into an easy, convenient, handy and controlled practice. The US Laser Corporation, NJ, is one of the advanced commercial firms that provide laser related engineering solutions. A lot of helpful information is presented at their website. Many papers regarding laser applications in welding were found in the Journal of Laser Applications, some of which are discussed later in this section.

Almost quarter of a century ago, laser welding was in its stage of inception, usually applied to only selected applications where no other method was deemed possible. With the progress of research in lasers and methods of application, laser welding is now a full-fledged part of the metal-working industry. From welding minute parts in a cigarette lighter to chassis welding in the automobile industry, laser welding has made its mark. There is yet a huge part of the industry that has not realized its applications, mainly because of the unfamiliarity with the operation and capabilities of a laser system. Other associated factors like expensive initial investments and environmental factors can be the reasons.

Laser Welding is a non-contact process that directs laser outputs of 2 – 10 kW into a very small area, on surfaces of parts that have to be welded. The basic process involves the laser beam making a ‘keyhole’. The liquid steel solidifies behind the traversing beam, leaving a very narrow weld and heat affected zone (HAZ). By heating the spot of laser focus above the boiling point, a vaporized hole is formed in the metal. This is filled with ionized metallic gas and becomes an effective absorber, trapping about 95 percent of the laser energy into a cylindrical volume, known as a *keyhole*. Temperatures within this keyhole can reach as high as 25,000 °C, making the keyholing technique very efficient. Instead of heat being conducted mainly downward from the surface, it is conducted radially outward from the keyhole, forming a molten region surrounding the vapor. As the laser beam moves along the work-piece, the molten metal fills in behind the keyhole and solidifies to form the weld. This technique permits welding speeds of hundreds of centimeters per minute or greater, depending on laser size. With the advancement in techniques for laser welding, new applications emerge which in turn accentuate further developments in techniques. Different types and configurations of welding demand varied styles and parameters of weld. This facility is also provided by laser welding.

Butt welding has become practically complicated for sheet metals as thin as 50–100 mm. In experiments conducted by J. Du, J. Longobardi (2001) [1.74] they introduced a new concept called **marginal lap welding** used to produce continuous and distortion-free welds for such thin sheets. As the energy loss due to heat conduction into the clamps becomes significant under this situation the input laser power has to be increased to produce an effective weld. Overlap welding creates large unwelded double layers which are a waste of material and result in undesirable weld configuration This paper investigates the effects of heat loss during marginal lap welding of ultrathin stainless-steel ~SS316L sheets, both experimentally and theoretically. The results show that a smaller clamp gap causes more heat loss into the clamps and generates a narrow heat-affected zone, which is found to be beneficial to the corrosion resistance of the weldment. In this study, experiments are carried out to illustrate the clamp heat sink effects on the geometry and corrosion properties of the laser-welded joints of ultrathin sheets. An analytic model is also developed to calculate the temperature profile, weld geometry, and heat loss into the clamps.

A continuous-wave Nd:YAG laser was used for the welding experiments of annealed SS 316L sheets of thickness 100 mm. The sheets were welded under different welding conditions. The corroded samples were analyzed with an optical microscope. The new process successfully eliminated the unmelted double layer problem. It was found that the percentage of absorbed laser energy lost into the clamp increases significantly as the clamp distance decreases. This results in a narrow heat affected zone, which is beneficial to the corrosion resistance of the weldment. A conduction mathematical model was successfully developed accounting for heat loss into the clamps. Its prediction was fairly consistent with the experimental results.

Another huge application of laser welding lies in the fabrication of large reactor vessels and storage tanks. The petroleum and chemical process industry invests huge amounts in storage and transportation of raw materials and products. A similar example of **welding stainless steel tanks with the help of Nd:YAG laser** was proposed by Yoshiaki Shimokusu, Seiji Fukumoto (2002) [1.75]. Laser beam welding is also utilized for manufacturing precise parts such as core internal parts in nuclear power plants (in this study for Mitsubishi Heavy Industries, Ltd.) that require welds of very high quality and where welding is processed on a large-scale and towards thick-wall products It is quite therefore necessary to ensure that the high power laser beam is delivered at the process and a deep penetration welding procedure is a must. To deliver a high power at the working material, an optical fiber transmission system was used. Pulse modulated laser welding techniques were developed to achieve deep penetration. It has been proved from this study that there are selective pulse duty and pulse duration values for optimum welding condition to obtain the best possible sound and efficient weld.

High power CO_2 laser welding made it difficult to secure the welding quality during the welding of thick plates because of the change in beam quality and the effect of laser induced plasma. Hence a 7 kW class high power yttrium–aluminum–garnet (YAG) laser was obtained for this study. The detailed observation of the weld pool and keyhole dynamics was captured using a high-speed camera and x-ray transmission system was carried out to understand high power YAG laser welding phenomena. The experiments were carried out to compare between CW and PW effects, study the change with pulse frequency, effects of pulse duty cycles and change in welding conditions.

The enhanced peak through the PW laser beam enabled deep-penetration welding with narrow bead width that could not be obtained by CW. Observations suggested that keyhole behavior depends on peak laser power, but penetration depth is decided by not only peak laser power but also the pulse duration after keyhole depth saturation. Out of the various pulse-welding conditions, pulse frequency and pulse duty cycle were optimized to realize high-quality deep-penetration welding. The weld bead thus obtained was found to be only slightly affected by the welding position and was confirmed to be applicable to large-scale products. The pulse welding enabled full penetration welding of 14 mm thick product, ensuring excellent penetration bead. The weld was confirmed to have excellent mechanical characteristics and corrosion resistance.

To enhance the quality of welds scientists began to study the interaction at the interface of the welding process. One such study was the **Interaction of the keyhole and weld pool in laser keyhole welding** by John Dowden (2002) [1.79]. Dowden mentioned that there was a presence of several components involved with the motion pattern of the liquid material in the weld pool in laser keyhole welding. Several experimental observations have shown not only that the liquid tends to move in the plane perpendicular to the axis of the laser, but also that it moves parallel to the laser beam. The author believes that Marangoni convection and viscous drag are the two phenomena that cause the vigorous motion observed in practice in the weld pool. The latter the intensely studied with a mathematical standpoint and its effects are clearly mentioned. Flow models are developed to predict the influence of flow in the keyhole. It is learnt from the results that flow in the weld pool and keyhole is very sensitive to external conditions. Incorporating the viscous drag effects could better predict the behavior of flow. The strength of the flow predicted, irrespective of the direction, shows that fluid motion induced by the vapor in the keyhole, which itself results from the ablation at the keyhole wall necessary to hold the keyhole open, must be considered to be an essential part of the problem of determining the quality and character of the resulting weld.

To control the effect of lasers to be as precise as possible one had to simply monitor the interaction taking place. As laser welding is becoming more and more common in various industries it is important to analyze the parameters that effect weld quality. One of the vital parameters in laser welding is the depth of weld penetration. In most applications, full penetration is desired. But as the welding process occurs it is difficult to evaluate this parameter in real time. A study conducted by Allen Sun and Elijah Kannatey-Asibu (2002) [1.76] investigates the potential use of variable sensors, which were previously studied to work quite effectively, for both laboratory and production settings. The purpose of this article was to assess the possibility of ‘acquiring **real-time nondestructive weld penetration detection using sensor fusion** of Infrared-IR, ultraviolet-UV, Audible sound-AS and Acoustic emission-AE sensors’. As signals from each of these sensing systems were acquired in real-time and transformed into the frequency domain for feature extraction, pattern classification was accomplished.

A CO_2 laser was used for both the experimental lap welding test in a controlled setting and also for the production in a power-train laser-welding cell. Four methods of sensor fusion were investigated

1. Data fusion with singular value decomposition
2. Feature fusion with class-mean scatter
3. Decision fusion with class-mean scatter
4. Decision fusion with singular value decomposition

The classification rate obtained with sensor fusion using minimum distance classification was 100% for laboratory data. On the other hand, when the same was applied to industrial data, classification decreased due to high variance of the features. By adding the quadratic classifier, classification was improved to 100% for ALL cases of sensor fusion. The authors plan to perform future analysis which will focus on the variable depths of penetration and evaluate the ability of sensor fusion to determine the degree of penetration during laser welding process.

Another similar concept in **Penetration control in laser welding of sheet metal** was proposed by S. Postma, R. G. K. M. Aarts, Johan Meijer (2002) [1.77] . As laser welding evolves into a common manufacturing tool in the industry it is the economics of the process that plays a very significant role to sustain itself. It is for such reasons that it is desirable to have the highest possible laser welding speed. Insufficient weld depth penetration is one of the limiting factors that define the speed of the welding process. The author here proposes to design a feedback controller system that can monitor the weld penetration and control the speed of the weld process.

In this research 0.7 mm mild steel plates were welded with a 2 kW Nd: YAG laser. The laser beam was transmitted through an optical fiber with a diameter of 0.6 mm. An optical detector placed inside the Nd:YAG laser source, measures the intensity of the weld-pool radiation (through the optical fiber) which is used as the input sensor signal for the feedback control system. The input of this model is the laser power and the output is the modeled sensor signal. The laser power is used as an actuator. Experiment cycles were run using this feedback mechanism.

Results show that the controller maintains full penetration during welding of tracks overtaking disturbances like sudden artificial power fluctuations and sudden speed changes. This feedback controller opens the possibility to optimize the welding speed without risking lack of penetration. As the system is automatic man-made errors are reduced and smooth consistent welds can be produced. Since the system accepts a range of reference signals (margin of deviation) the manufacturer can set a personal required speed limit corresponding to the required quality of weld. Setting a higher reference signal reduces the laser power demanded by the controller, thereby making it possible to increase the welding speed further. However a too high reference signal may produce large fluctuations on the laser power or even an unstable feedback, which in turn amplifies the fluctuations. This vicious cycle can destruct the whole processing sample.

Another method of weld monitoring was put forward by J. Tu, I. Miyamoto and T. Inoue (2002) [1.78] in their paper **'Characterizing keyhole plasma light emission and plasma plume scattering for monitoring 20 kW class CO2 laser welding processes'.**

Many other studies involving other laser parameters and different welding techniques are being studied. Some interesting approaches towards enhancing welding systems are given below.

• Prevention of welding defect by side gas flow and its monitoring method in continuous wave Nd:YAG laser welding

Kenichi Kamimukia) and Takashi Inoue
Kouzou Yasuda, Mikio Muro, and Tokuhiro Nakabayashi
Akira Matsunawa

19 March 2002, Laser Institute of America

Among the critical parameters which ensure high quality welding in laser welding of thick plates are the 'reduction of porosity' and 'monitoring the keyhole/molten metal behavior'. As several previous experiments had shown positive outcomes with CO_2 lasers while using different techniques for increasing weld quality, this investigation involved applying a side gas flow to prevent the porosity in the bead on plate welding. Within the same experiment, a reflected Ar^+ laser was used in the same axis as the Nd:YAG laser beam to help measure the light emission from the weld as monitoring signals. The effect on penetration shape and the number of pores was investigated under various side gas conditions.

In the experiment a continuous wave Nd:YAG laser resonator of 6 kW maximum output power was used, and the laser power on the surface of test plates was adjusted to 4.5 kW. The laser beam was transmitted through an optical fiber of 0.6 mm core diameter. The nozzle angle, gas pressure and nozzle height of the side gas were varied. It was found that under the optimum side gas condition, pores in the weld metal could significantly decrease, the penetration depth increased slightly, and the bead width became narrower. Under that condition, moreover, the generation of spatters was quite few. An acceptable limit of the transverse misalignment of the side gas nozzle position was said to be 1 mm. Any alteration or misalignment beyond the optimum side gas condition produced negative results. These results could be detected by using the above mentioned monitoring signals.

The figure below (from the paper) shows schematic illustrations of the side gas jet/molten metal interaction that has been assumed on the basis of above experimental results. It is interesting to note how by a simple change in the alignment of the side gas would cause a drastic effect on the welding process and also in the quality of the finished product. When the nozzle is aligned behind the optimum position the side gas jet pushes the molten pool directly in the welding direction and the keyhole opening becomes narrower.

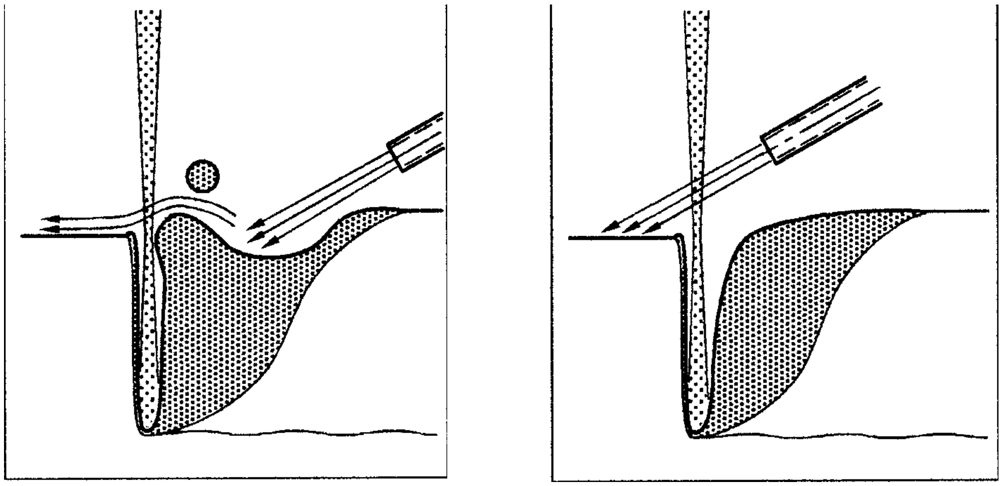


Fig.1.20: *Nozzle placed behind or in front of the optimum position*[1.80]

The optimum position of side gas nozzle deeply dents the pool surface resulting in a widened and much stable keyhole. The return air helps push the molten out of the keyhole and into the molten pool at the surface.

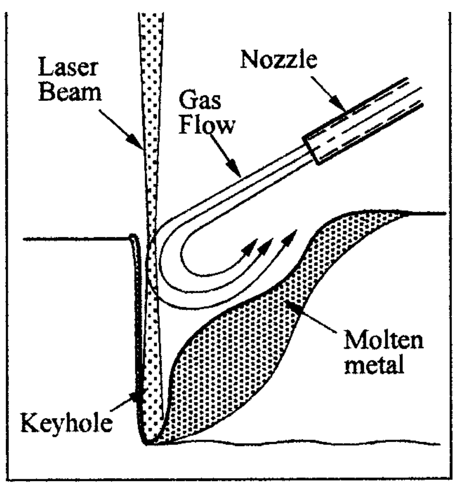


Fig. 1.21: *Nozzle placement at the optimum position*[1.80]

- **Effect of wire feed position on laser welding with filler wire**

A. S. Salminena) and V. P. Kujanpaa

27 March 2002, Laser Institute of America

The utilization of the laser welding process with filler wire addition is often considered a complicated and difficult process which has too high accuracy demands for a work shop floor. This study shows the effect of some of the most important welding variables to the quality and efficiency of laser welding when welding with filler wire. The material used was a common structural steel St52/37 of 6 mm in thickness. The joint type used was a butt joint. Acceptable weld quality was achieved with most of the tested parameter combinations. The effect of the wire feeding parameters for the acceptable weld quality was smaller than expected. The variations of weld quality caused by the non-optimized aiming of filler wire can be compensated by the adjustment of the filler wire feed rate and the heat input. The quality of the welds was compared with developed weld quality index. The increase in heat input will make it possible to accept wire feeding to a lower position or from backwards compared to the welding direction. The misalignment of wire in the transverse direction to welding direction and laser beam optical axis causes problems that may lower the quality of the weld. The comparison of the welds with variable air gap widths showed that the weld width is more dependent on the heat input that on the original gap volume.

1.5.1.2 Secondary Industrial Applications

Unlike the primary applications which are applied on the work-piece directly there are many other applications[1.9] where Laser can prove to be helpful with simply peripheral roles.

- *Meteorology & Surveying*: One of the simplest and widely used applications is using laser as a non-material straight line for construction purposes like buildings, tunnels, pipes etc. Laser Radars are yet another very useful appliance. Short pulses from a solid state laser are directed towards a target and the return pulses are timed. Results can be obtained to a high level of accuracy. Lasers also facilitate the measurement of very small movements thus allowing a lot of functions such as security and alarm systems.

- *Optical Communications*: Transmission of data is by far one of the most significant uses of laser technology. As we know data can be transmitted through the atmosphere but could easily be adversely affected by the atmospheric conditions, pollution, low clouds and aerial objects. An attempt was made by scientists to come up with a scheme that could protect the light from interference by shielding it in metal tubes and propagating it through using specially designed mirrors and thermal gas lenses. A development in the early 1970s of hair-thin strands of encased glass, called fiber optic waveguides propelled a lot of telecommunication companies to transmit voice, data, and video utilizing fiber optics. Optical waveguides transmit light many kilometers with very low losses, and with greatly improved reliability and security. Telecommunications today relies on photons, as tiny semiconductor lasers routinely transmit light pulses carrying billions of bits of information per second over these glass fibers. They are light in weight and are not subject to the same type of electromagnetic interference which is encountered in other conventional techniques.

- *Remote Sensing*: The Laser proves to be an ideal tool for non-intrusive remote sensing where a material probe would be in jeopardy or the environment is hostile. The technology is now used commercially for a lot of purposes. One of the related techniques is known as the Doppler-effect, which is, using light instead of sound to measure the velocity of large or minute particles. We can also detect non-homogeneities in moving fluids. Other techniques involve the measuring of transit time of a particle between two laser-illuminated regions and to deduce the velocity from the knowledge of their separation. Potential applications include:

- True air speed measurements
- Measurement of wind shear
- Monitoring thickness of surface corrosion (power stations)
- Current and voltage measurements in a high voltage power transmission system

Useful developments towards the industry[1.10]:

- Laser excitation of thermal waves
- Comprehensive optical diagnostics
- Laser-projected 3D volumetric displays
- Fiber opto-acoustic feedback in pulsed laser systems

1.5.2 Military Lasers

Lasers have emerged into the arena of tactical battlefield with uses such as range finders, target designators, and guidance systems. With the current pace of advancement in laser technology it is quite feasible that use of the military lasers as a tactical weapon is far from unlikely. As for now it does have a few disadvantages like size and weight that must be overcome before they become a pragmatic technique. Laser applications will continue to be added to the battlefield as technical problems are overcome. The light-sensitive targets, for example, the human eye may be the first targets of laser use on the battlefield as an offensive weapon. Lasers of different wavelengths can cause damage ranging from flash blinding or even complete permanent blindness. The technology for this type of weapon exists today, and employment is easily possible within the next few years. The use of lasers largely as explosive or deteriorating weapons of destruction is not in the near future. The aforementioned obstacles still hinder the transpiring idea of practical battle field lasers.

Involved in a warfare it is has always been the aim to achieve the highest strength in firepower by focusing the available technology at the right place and time. As we move into the next decade, we are again on the verge of fielding additional "higher technology" artillery. The next generation of tactical battlefield weapons will include directed energy or laser weapons against men, electro-optical sensors, pin-pointed target attack and other light-sensitive targets. Speaking in late 1981, Defense Advanced Research Projects Agency director Robert Cooper[1.11] said that $2 billion was "an enormous amount of money...for what still remains an exploratory development program. Yet he added that "it's the collective judgment of high officials in the Pentagon that laser weapons present a high potential for payoff. There is a good chance that we will put a high-energy laser weapon system on the battlefield."

1.5.2.1 Types of Military Lasers

Ever since the invention of lasers by Townes & Schawlow, tremendous advances in research and technology have taken place. Among the earliest of lasers, in the *ruby laser*, synthetic ruby crystals are utilized as the energy absorbing material. This medium is not efficient, as only about 1% of the light that goes into the rod emerges in the form of laser light. Most of it ends up in the form of heat, which must be removed or its effects on the laser rod may break up the beam or damage the rod itself.

The heat removal system required in *ruby and other crystalline or glass lasers* poses a serious problem. Although the external light source efficiently deposits energy throughout the transparent rod, the excess heat is much slower in leaving the solid. This fact, combined with some complications due to energy levels in the material, limits operation of the ruby laser to no more than a few pulses per second except at very low power levels, and also sets upper limits on the actual output power.

Crystalline or glass lasers are easier to cool, and can produce much higher peak power, but they are not practical from a military tactical standpoint. They can only produce about one shot per day, due to heat dissipation problems.

For continuous operation at high power output, a laser material that can quickly dissipate residual heat is necessary. Much research has been done with gas lasers; however, military uses for *gas dynamic lasers* are limited. The atmosphere does not transmit the beam well, and there is very little tolerance for error in design or manufacture of critical components. The size and complexity of gas dynamic lasers have little tactical application on the battlefield.

Most demonstrations of laser weapons in the works involve the *chemical laser*. As its name implies, it derives its energy from a chemical reaction, the combination of hydrogen and fluorine to produce molecules of hydrogen fluoride-in a vibration ally excited state. The term "chemical laser' usually refers to a hydrogen fluoride laser. The reaction in a chemical laser can be triggered by an electrical discharge. The starting point is a fuel containing hydrogen and an oxidizer containing fluorine.

Because of problems with fuel stability, however, substitute fuels are frequently used. The laser beam is produced through a chemical sort of chain reaction. There are some drawbacks. The cavity into which the laser gas flows must be kept at a very low pressure, typically 1% or less of atmospheric pressure. There must be a way to get rid of the gas after it is passed by the laser mirrors. For a space based laser system, it could simply be vented outside. On the ground, however, because of atmospheric pressure, a vent must let the air in. This is necessary since hydrogen fluoride is toxic in concentrations of as little as three parts per million. The Army is currently working on methods to pack the waste hydrogen fluoride into canisters to prevent inadvertent venting into the air.

From a military point of view, chemical lasers have some major advantages over gas dynamic types. One is that energy can be stored more compactly in the chemical form. On a battlefield, where portability is the key to moving quickly, ease of storage is a must. Another advantage is the shorter wavelength produced by the chemical laser. The short wavelength creates a smaller focal spot on the target with more concentrated energy. This shorter wavelength, however, creates the need for more accurate optics. There appears to be no free lunch in military application of laser beam technology; however, from research being done in the field, military applications seems to be unlimited.

1.5.2.2 Military Applications of Lasers

Laser weapons find their use in both the traditional military categories: tactical and strategic. Tactical weapons are those intended for use in battles between armed forces on the ground, at sea, or in the air which operates over short distances. On the other hand, strategic weapons are intended for use against other targets, such as arms factories, logistics installations, or for defense of such strategic targets against enemy attack. Satellites, intercontinental ballistic missiles, and long-range bombers are considered strategic armaments; rifles, helicopters, short-range missiles, and most fighter aircraft are considered tactical.

Tactical uses of ground-based laser weapons are being pursued by the Army. Research is being conducted on the feasibility of placing a moderate or high-powered laser into a tank or other heavily armored vehicle. These ground-based lasers would operate over ranges of a few kilometers under extremely demanding conditions, including being subject to dust, dirt, smoke, and enemy attack. The laser weapon could be used against anything that moved on or flew above the battlefield. Lasers could destroy targets by causing mechanical damage, triggering explosions of fuel or munitions, or knocking out enemy sensors. They might be used to blind soldiers, temporarily or permanently. It will be some time, however, before there is enough laser firepower designed to incinerate individual soldiers. The idea seems to be enchanting but as it turns out bullets are cheaper. Clearly, directed energy weapons need not burn a hole through you; they need only blind or dazzle your eyes or electro-optic sensors to make you more vulnerable to the conventional weapons populating the battlefield.

The Navy has considered putting laser weapons on ships to destroy attacking missiles - hopefully faster and more effectively than conventional weapons. The PHALANX Gatling gun system now in use can fire 6,000 rounds per minute, but that might not be enough to blunt a cruise-missile attack. The operating environment of these sea-based lasers is also demanding. Salt water and humidity present a difficult problem to overcome. Compactness of the system is not as critical an issue as for ground or air-based systems.

Aircraft carriers can easily accommodate larger laser systems. The Air Force is studying the feasibility of putting laser weapons in planes to defend against missile attack and against other aircraft. The biggest problem is bulk and weight; a laser weapon can't defend a plane unless it can fit inside one. The Air Force would like to put lasers in fighters, but because of size and weight, bombers might be more practical.

The strategic use of the laser falls into two research categories: near-term research in anti-satellite weapons and long-term efforts to develop a system for missile defense - also known as the Strategic Defense Initiative (SDI). The military role of satellites particularly in surveillance, arms-control verifications, and communications, has made them potential military targets. The sensitive optics on these satellites is vulnerable to an overload of light and easy targets for laser attack. The SDI lasers that are currently on the drawing board represent the most significant role ever proposed for laser technology.

1.5.2.3 Tactical uses of Lasers in warfare

Antipersonnel: We can currently boast of technology that could melt soldiers with intense laser beams, but the bulky size of the systems necessary to do so on the battlefield would make the whole idea impractical. A tightly focused laser beam could burn the skin, but would hardly be an efficient way to burn a man to death except at near point blank range

The eye however is vulnerable because it is similar to other types of optical sensors, that is, it is extremely sensitive to light. This sensitivity varies widely with wavelength and is highest at visible wavelengths. Staring directly at the sun or directly into a laser beam carrying only several thousandths of a watt of visible light can cause permanent damage to the retina. This occurs because the lens of the eye focuses visible and near infrared light, concentrating its power to high enough levels to burn the retina. Higher powers take less time to cause damage, with short, intense pulses being particularly dangerous. The result is not total blindness, but partial obstruction of vision due to blind spots, which may be permanent or temporary depending on the power of the laser. The type of physical injury that a laser can cause depends on the laser power, pulse duration, and wavelength. The wavelength is particularly critical in determining what type of eye damage, if any, will occur. Light with wavelengths between about 0.4 and 1.4 μm, in the visible and what is called the near infrared regions, can penetrate the eyeball. The lens focuses this light to a pin point on the back of the retina which will cause bleeding and a permanent blind spot. Light that can’t penetrate the eye can still cause damage. Intense ultraviolet light can cause a variety of problems, including temporary blindness and a form of damage to the cornea that is similar to sunburn. The cornea burn depends on total exposure with little sensitivity to how fast or slow the exposure occurred. Like sunburn, the effect typically takes a few hours to show up.

Long exposures to long wavelength infrared light such as the one produced by a chemical fluoride or carbon dioxide laser can also burn the cornea. The eye's natural blink reflex provides a safety mechanism because infrared intensities high enough to cause damage to the cornea also cause pain. Continuous laser powers of more than 10 watts/cm2, roughly the intensity of a 100,000w beam focused to a 1m spot, would be needed to damage the cornea before the eyelid could shut, once the eyelids closed, the absorption of the skin would prevent long infrared wavelengths from reaching the eye. This intensity is possible on the battlefield.

Temporary flash blindness is another snag that can be inflicted which can prove to be a serious problem on the tactical battlefield. This occurs any time a bright flash of visible light dazzles the vision of the receiver. Dazzling can occur by staring directly at light brighter than the noonday sun, or by illuminating an extremely bright flash in one's direct line of sight. Anyone who has been on the receiving end of a flashbulb has no doubt experienced this form of vision impairment.

Knowing such threats it is important to initiate protection against laser effects. There are some simple measures that currently provide protection against laser effects. Ordinary clothing and in the future some type of aluminum-foil armor may be used as body protection. Special safety goggles have been developed that absorb laser light at certain wavelengths. The problem on the battlefield is that you don't know what type of laser you'll be facing. Even then, changing the wavelength is a simple matter of turning a dial. There are goggles that protect against all wavelengths. Unfortunately, the wearer can see no visible light due to the darkness of the glass. The day of the "ray-gun" is not yet here for two reasons. First, a laser "ray-gun" for use as a soldier's individual weapon currently presents little advantage over a conventional weapon. Both are line of sight weapons requiring visual, straight-line, target acquisition. There is no cover or concealment advantage; the soldier must still physically see his target to kill it. Secondly, current technology still requires that lasers be of considerable bulk and cost. This virtually eliminates the laser as an individual weapon. In the antipersonnel role, lasers may be centrally located, and easily used to blind or flash blind enemy personnel.

Blinding sensors: The priorities on the battlefield make electronic eyes more inviting targets than human ones. Many of our modern weapons rely on sophisticated electro-optical sensors. Laser attacks on battlefield sensors can be accomplished by several means. The first is by blinding sensors with modest power laser beams, which would cause them to lose track of what they were observing. If the sensor is guiding a weapon to its target, such blinding could cause it to miss. Another way to attack a battlefield sensor would be to confuse the sensors that trigger the explosion of a warhead on a missile or bomb. This could either cause a premature explosion that does not harm the target or prevent the warhead from exploding at all. One other way to disable a battlefield sensor is to cause thermal or physical damage to the sensor itself or to the optics that focus light onto it, again leading to a miss.

The emphasis on lasers used against sensors is not so much physical damage, but rather damage to its electronic eyes. Most sensors are designed to operate over a limited range of wavelengths and light intensities. Generally, the longer the wavelength and the greater the sensitivity, the more vulnerable the sensors are to laser attack. Sensors of visible light are usually made of silicon and tend to be rugged. The most vulnerable sensors are those designed to detect thermal radiation from ordinary objects at room temperature. A Forward Looking Infrared Device (FLIR) operates in this spectrum.

Other infrared sensors, those operating at shorter wavelengths, are used in heat-seeking missiles. An infrared laser could be used as a decoy to steer the missile along the wrong path, or could burn out the sensor, blinding the missile completely. With sensors used in large numbers on the battlefield, they are particularly vulnerable to laser attack. Unlike the human eye, however, electro-optical sensors can be more easily "hardened" against the laser threat. With appropriate filters and circuitry electro-optical devices can be designed to minimize laser damage.

Physical damage: A high energy laser is expected to take somewhere between a second to several seconds to do enough physical damage to kill a target. An intense beam could do the job in a short pulse, if the beam could make it through the atmosphere. A physical "kill" of a piece of equipment does not necessitate the total disintegration of the target. A laser focused on the wing of an aircraft could produce enough heat to cause the fuel tanks to explode. Helicopter rotor blades and fuel tanks are also vulnerable. Because much higher intensities are needed to cause mechanical damage than to zap human or electronic eyes, physical damage is harder to produce. As laser beam intensity in the atmosphere increases, harmful atmospheric effects begin to manifest themselves. High energy laser beams are liable to be bent away from their targets or dispersed by thermal blooming effects in the atmosphere. The solution to these problems is certainly within current technological capabilities. The military "destructor beam" definitely is in our future tactical arsenal.

We stand at the verge of a revolutionary phase in the development of weapons for modern warfare. Lasers are the leading edge of the new group of directed energy weapons. Our current uses of lasers on the battlefield have thus far been limited to range determination, target designation, and missile guidance.

As has been pointed out, however, the laser is capable of much more on the battlefield. Based on the available technology the military cannot be totally reliant on lasers as a substitute for conventional weapons any time soon. The additions of new-purpose laser weapons will not occur overnight. The first new generation weapons will target the human eye, as that presents the softest target especially during night operations. At night, the eye reacts overtly to lower ambient light by opening up and gathering in more light. This involuntary regulation of the eye increases its vulnerability to laser beams because more energy is permitted into the eye and is focused down onto a small spot on the retina. At higher powers, light receptor cells are literally blown off the retina, permitting blood to leak into the eye causing swelling and often shock."

Our first priority in defending against the next generation of laser weapons should be toward the development of eye protection for all wavelengths of lasers. A blind soldier, sailor, airman, or Marine is as good as dead in a fast moving tactical scenario. As laser technology grows it is clear that the laser's role on the tactical battlefield will greatly expand from present day uses.

1.5.3 Laser Cleaning: A new recruit in Conservation

The choice of Laser parameters such as wavelength, power, beam size, pulse-frequency etc. and the degrees of freedom of one with respect to each other makes it specific for each and every little particular application. Selecting the most optimum and well-balanced constraints, Lasers can prove to be an extremely precise tool which would fit the described job most appropriately. As cleaning requires a very careful and accurate procedure, Lasers have an enormous potential in conservation. The controlled manner in which the cleaning process can be carried out gives it the literal edge over any other traditional cleaning procedures or process techniques.

Cleaning often involves the removal of layers of dirt strongly bound to a delicate and crumbling but valuable surface. One of the most common techniques used is the mechanical method of abrasive-cleaning[1.12]. This procedure involves microscopic abrasive particles or water molecules in a stream of compressed air as the cleaning medium. Such techniques do not ensure the safety of the underlying surface, either on a macroscopic or even microscopic scale. It is the inability of the cleaning medium to distinguish between what needs to be removed and what is to be left unharmed that causes the damage. However, an alert handling of a suitable combination Laser helps the conservator to be able to precisely remove the dirt without injuring the underlying fragile surface. The option of mechanically bombarding the surface with hard abrasives or water molecules can be efficiently replaced with a pulse of light such that the impact on the surface is pretty negligible; essentially a non-contact process. The point of difference can be based on the ability of the laser to successfully discriminate between a clean and to-be-cleaned surface. As the parameters of the Laser decide its degree of interaction with an objects surface, it can be so designed to carry out the defined work- to remove dirt and not the art surface.

Other methods of cleaning are based on water-jets and on applications of chemicals to selectively remove dirt. The underlying idea of chemical cleaning holds that the selected chemicals dissolve the dirt leaving the object surface unharmed. This practically seems to incorporate the Laser idea of selectivity but as we perform chemical cleaning on a larger scale, there are many more risks involved both to the surface and to the conservator. Similar is the case of Water-based cleaning. In cases of acid chemicals, long term problems arise like

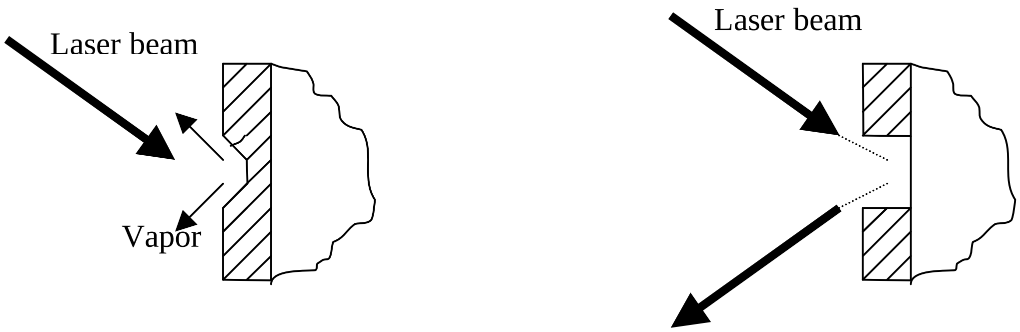
- Accelerated weathering, staining, bleaching & depletion of material
- Salt distribution and efflorescence
- Stronger acids may etch the surfaces of minerals
- Increased water retention leading to growth of damaging organic algae
- Inability to control the extent of chemical absorption into the material
- Inability to halt chemical fluid migration towards damage susceptible areas
- Damages can be irreversible

Lasers on the other hand offer a very advantageous approach as compared to the conventional techniques.

- *Non-contact:* Since the energy provided is in the form of light there is minimal or negligible contact with the object surface
- *Selectivity:* By choosing the favorable parameters selective cleaning can be carried out
- *Localized Action:* Laser beam can be adjusted to work between fractions of 1 millimeter-1 centimeter. Both precise and large scale functions are accessible.
- *Controllable:* The procedure can be halted at will. No secondary effects involved.
- *Instant feedback:* Surface monitoring is possible even while the process is at work.
- *Environment friendly:* Does not produce even minor quantities of waste material. Moreover it does not involve nay hazardous chemicals or solvents.

A physical perception of Laser removal of selective surface layers from a reflective surface by means of optical absorption can be traced back to the ‘Laser Eraser’ which was a proposed tool from Arthur Schawlow (1960). John Asmus and his colleagues then put forward an idea by which the similar principle could be applied to remove black encrustations from white marble. Asmus supposed that if this, the ability to detect between layers of dirt and an object surface, was to be effectively proven in practice it would be a major advancement in cleaning practices.

In 1973 Asmus and his colleagues published a paper (Asmus, Murphy and Munk, 1973) describing initial work in which a pulsed ruby laser was used to remove dark encrustations from marble structures.

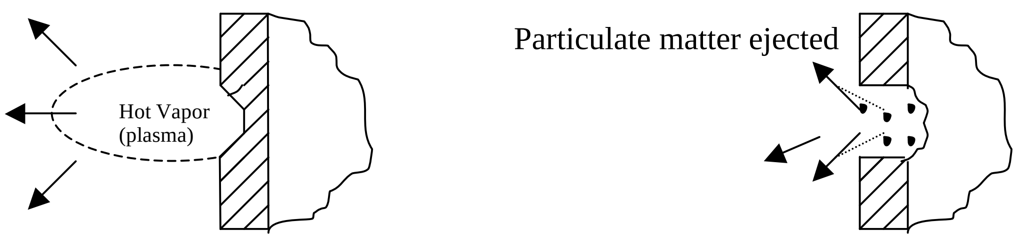


Intense absorption of laser energy by the dark encrustation leads to the vaporization of the material

Once the encrustation has been removed further pulses are reflected from the weakly absorbing material.

Fig.1.22: *Test conducted using Normal mode cleaning*[1.12]

Tests were also conducted using a Q-switched laser radiation, which were found to be more efficient than the normal mode in removing material since the pulse length is short such that there is lesser thermally-induced micro cracking.



Early vaporization of encrustation leads to plasma formation. Plasma rapidly absorbs the laser radiation and a microscopic compression is applied to the surface.

As soon as the laser pulsing is switched off the plasma expands away from the surface causing it to relax and a thin layer of material is ejected.

Fig.1.23: *Test conducted using Q-switched laser radiation cleaning*[1.12]

A lot of research came into being with respect to interaction of different kinds of lasers with many different materials. The potential of lasers which could be selectively applied to suit ones required results became a hope for many scientists to come up with their own specified experiments. Many interesting finds[1.12] included:

- Ability of Laser to deposit 'spatially and temporally localized energy in a material' could be used to treat deteriorating surface flashing on antique stained glass. (Asmus, 1975)
- Possibility of using pulsed radiation to remove lime coatings from frescos. (Asmus, Westlake, Newton, 1975)
- Study of surface morphology of laser cleaned stones. (Asmus, Seracini & Zetler, 1976)
- Cleaning of leather & vellum using ruby lasers (Vitkus & Asmus)
- Removing dirt off oil-paintings using excimer lasers. (Carlyle, 1981)
- Successful comparison of laser cleaning with air-abrasive cleaning. (Verges-Belmin and Orial, 1993)
- Precise and controlled cleaning of terracotta surfaces using a Q-switched Nd:YAG laser. (Larson and Cooper, 1996)
- Using Nd:YAG laser to remove dirt crust and stains from a silk textile model. (Oger and Polonowski)
- Frequency doubled output from a Nd:YAG laser & a dye laser were successfully used to remove fungus-induced stains from paper. (Szczepanowska and Moomaw, 1996)
- Successful use of ultraviolet lasers in conservation of paintings. (Morgan, 1993; Fotakis, Hontzopoulos, Zergiotti et al., 1995)

With all the results of previous and the ongoing researches a number of areas can be highlighted which may require further study:

- The effectiveness of the technique on different types and colors of marbles and other materials
- Effectiveness of different wavelengths and pulse lengths in cleaning
- Effects of laser cleaning on surface of impregnated marble
- Determination of optimum energy densities fro cleaning in each case

This short review about laser cleaning in conservation does not cover all the research that has been accomplished through the years. A lot of interesting work can be found to be explained in the proceedings of the two international conferences, Lasers in the Conservation of Artworks (LACONA) I and II, 1995 &1997.

1.5.4 Lasers in Chemistry[1.13]

The field of chemistry today faces revolutionary changes with the introduction and development of recent lasers. The ability of chemists to creatively utilize the required properties of lasers helps them in many areas of this field. The intense monochromatic light from lasers has found application in both physical and analytical chemistry. Laser light is used as a photonic reagent to precipitate reactions, as a probe into atomic energy states and even as "tweezers" in sub cellular research. Discussed in the following few paragraphs are a few astounding ways by which the lasers have been introduced to perform required chemical processes.

1.5.4.1 Using the Laser as a probe

Lasers have emerged as potential tools frequently used to study chemical reaction pathways and molecular structures. Briefly demonstrated is the diversity of investigation employing laser photons as chemical probes, thus promoting a drive to discover new avenues for laser utilization.

Molecular events occurring in any reaction or such situation (like transition state processes, chemical transformation, fluorescence etc) are in the order of pico or femto seconds. It is only with the means of a fast probing mechanism (*pump probe technique*) that such a performance can be achieved. Another indispensable component is the availability of a fast analytical technique which can indirectly measure the concentrations of the reacting and emerging species. Physical properties which are linearly related to the concentration of the amount of species involved can be regarded as the most convenient techniques of probing for different kinds of analysis. Few of the studies related to the probing research were:

• *Ultrafast Spectroscopy of ligand binding reactions:* The objective was to study the dynamics of ligand hemoglobin associations and conformational changes. The Laser system was provided to provide ultrafast excitation to induce dissociation and to monitor subsequent absorption changes, conformational changes and ligand rebinding. The short pulse duration of the laser (pico or femto seconds timescale), its monochromaticity & wavelength tunability helped in the resolution of ultrafast dissociations.

• *Reaction Dynamics in ultrafast regime:* The objective was to closely follow the rate of unimolecular dissociation of a model triatomic compound ICN in real time & gain in the process of a map describing the potential energy surfaces. The laser system generates excited ICN molecules that the tunable probe laser beam interrogates as a function of time and wavelength. The femtoseconds' pulses follow the time course and the fluorescence induced by the laser probe supplies the analytical signals to monitor the ICN.

• *Photoinduced electron transfer:* The main objective was to monitor the kinetics of Photoinduced electron transfer to generate charge–separated species. The laser system provides ultrafast excitation to generate the lowest excited state and to monitor the absorption of the transient radical pair formed upon subsequent electron transfer. The pump probe precisely monitored the intramolecular electron –transfer chemistry arising from the generation of excited states and also the subsequent decay of the charge-separated state.

• *Lasers & Multiphoton spectroscopy:* Spectroscopy was prevalent before the advent of lasers. What was neat about lasers that gave spectroscopy a new outlook? It was simply the intensity and the immense radiation associated with lasers which made this technique so viable.

• *Hidden electronic transitions:* The objective was to study spectroscopically excited electronic states that could not be achieved by normal single photon spectroscopy due to selection rules. The Q-switched laser provided very high photon fluxes suitable to increase the rate of two-photon absorption.

• *Polarization in Multiphoton spectra:* The objective was to identify the excited electronics states of dichlorine by the study of the vibrational – rotational spectra. The high power from the laser promoted two-photon absorption and controlled polarization provided fine control over the energy states studied.

• *Airborne remote-sensing of Laser-induced Fluorescence:* The objective was to use non-invasive, remote measurements, conducted from aircrafts, of laser-induced fluorescence of terrestrial & oceanographic targets which are utilized to detect a variety of conditions including oil-spills in marine environments and physiological states. The laser was successful in affording high powered and tunable excitation from high altitudes under a range of light conditions (cloudy, dark etc)

Other topics ventured are separation & analysis of mixtures using Laser-induced fluorescence detection, laser light scattering, Mass spectroscopy and also lasers in photoacoustics.

1.5.4.2 Using the Laser as a Reagent

The most widespread application of lasers in the field of chemistry is to handle it as a reagent. It is one of the early and most interesting applications with laser photons. With the ability of lasers to cause chemical change they can be manipulated to selectively control the direction of a reaction and the also the emerging products and their properties.

The option of selectively exciting only the required reactants and also the level of excitation can be achieved by the use of lasers. Laser parameters such as wavelength tunability, monochromaticity, intensity and mode of operation makes this technique so flexible for the chemists needs. The wavelength tunability enables precise irradiation even in the case of organic molecules which have brad spectrums of absorption, hence avoiding simultaneous irradiation of needed and unneeded components. Intensity of irradiation is very crucial for multiphoton reactions. Also, the low divergence of lasers permits light from the source to be propagated through long distances giving an advantage in designing the experiments.

Lasers are finding their way into fields like photochemistry, surface chemistry, solid preparations & Semiconductor processing. Some of the researches which look into such cases are:

- Lasers in the synthesis of fine chemicals
- Lasers as photocatalysts
- Lasers in impurity removal
- Laser-based synthesis of ultrafine materials
- Laser-based synthesis of superconducting materials
- Bond-selective chemistry of light atom molecules

1.5.5 Oil and Gas Applications

It was research into the failure mechanics attendant to rock failure using high-powered lasers that led to the laser being considered as a tool that could revolutionize oil-drilling practices. Through the efforts of the Gas Technology Institute (GTI) and Department of Energy (DOE), it has been demonstrated that lasers can be utilized for not only drilling rocks efficiently, but also accomplishing the drilling in an eco-friendly manner. The principal hurdle for drilling with lasers is the delivery of power to the drilling-surface. Given this, the use of lasers for this purpose awaits further technological developments. Other uses for the laser in oil-field applications have however evolved and include well-perforating and remediation of well bore damage. Other applications under investigation include the use of lasers for stimulation of wells and the use of ultra-high powered lasers for creating an impermeable sheath that has the potential to replace casing.

1.5.5.1 Laser Drilling

The capability of the laser in terms of developing usable energy led scientists to investigate its applicability to the drilling of rocks. Among the early scientists[1.27] who initiated investigations into the use of lasers for drilling F. Moavenzadeh, F.J.McGarry & R.B.Williamson (1968), Farra & Nelson (1969) , Jeffrey P.Carstens & Clyde O Brown (1971), Jurewicz & Greenwald (1973), Norton (1966). W.C. Maurer collected the Research and Development regarding the topic and published the collective findings in a book entitled 'Advanced drilling techniques.' [1.27] W.C. Maurer defined four methods for the excavation of rocks:

- Thermal spalling – occurs when the high stresses resulting from rapid surface heating exceeds strength of the rock,
- Melting and vaporization – lasers and electron beams possess the power necessary to melt and vaporize almost any kind of rock,
- Mechanical breakage – rock failure resulting from impact, abrasion or erosion,
- Chemical reaction –dissolving rock through the interaction of the drilling fluid and rock.

Common to drilling research are definitions that are used to quantify and qualify the energy necessary to induce rock failure. One such term is the **Specific Energy (SE).**[1.27] **Specific Energy** is the amount of energy required to remove a unit volume of rock and is defined as:

$$\text{Specific Energy } E = \frac{EnergyInput}{Volume \ldots removed} = \frac{P}{\left(\frac{dV}{dt}\right)} \quad (\text{J/cm}^3) \qquad (1.3)$$

Where:

P = Power Input (Watts)

dV/dt = Volume Time Derivative (cm^3/sec)

When high power laser beams are focused on a rock, heat is rapidly produced resulting in melting and vaporization. As is illustrated on Figure 1.24, the volume of the rock that is affected by the laser energy is marked with a dotted line. The rock in the heat-affected zone is thermally degraded by a combination of mechanisms (Brown, 1958) [1.14] that results from the action of the laser:

- Intergranular separation due to phase transformations,
- Gross chemical changes,
- Intergranular corrosion,
- Gas or water pocket expansion,
- Intergranular separation due to anisotropic thermal expansion,
- Thermally induced fractures

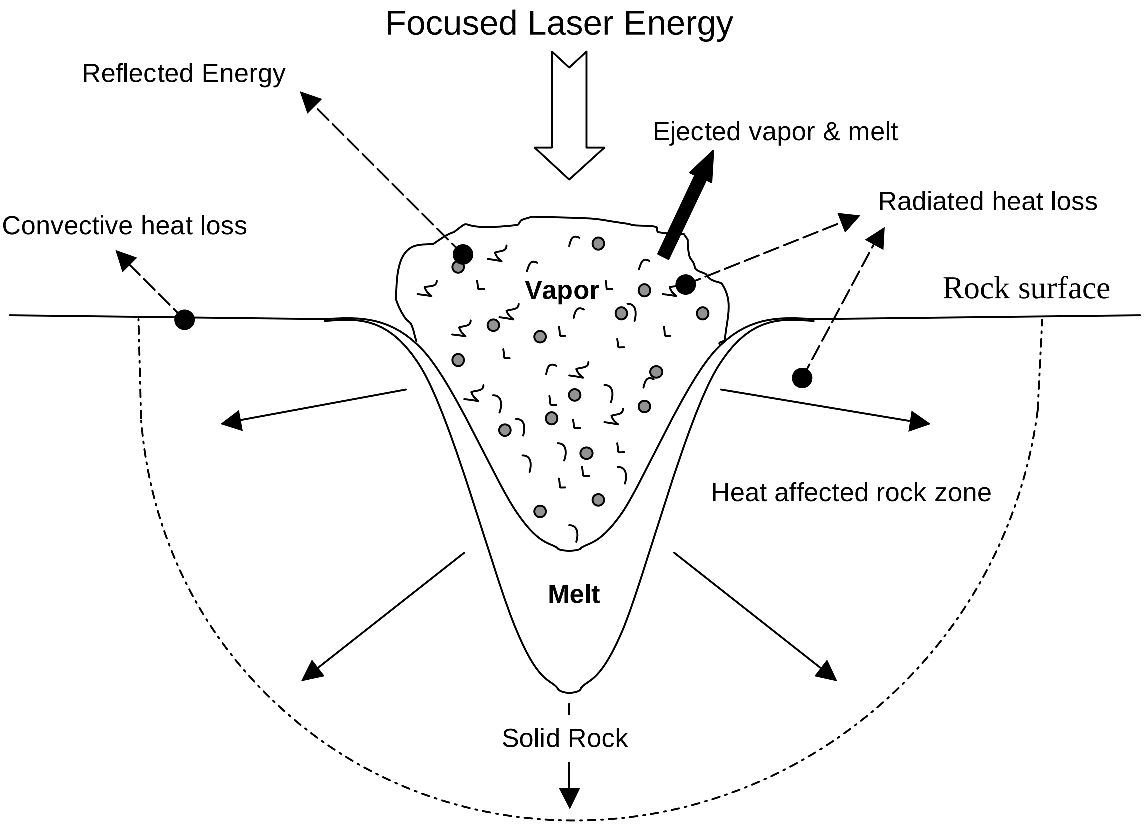


Figure 1.24: *Rock interaction with a laser beam (Jurewicz et al., 1974A)* [1.22]

The net effect of these mechanisms is to create substantial weakness in the rock and initiate free faces through which fractures can propagate. The impact of the laser therefore is to improve the effectiveness of cutters in breaking up the rock.

1.5.5.1.1 Laser Drilling; as applied to the Rock & Mining Industry

Moavenzadeh et al. [1.27] tested the impact of a laser beam on the flexure-strength of marble and granite beam samples. These tests were using a 0.75-kW CO_2 laser and included the evaluation of both 3.0-cm diameter focused and unfocused lasers. The results indicated that the unfocused lasers were more effective than focused lasers in reducing the flexure strength of the samples tested.

Williamson et al. [1.41] extended these experiments to investigate the time dependency of lasing. Using a 5-kW unfocused laser, tests were conducted using samples of granite. The results of these tests are shown on Figure 1.25 and indicate that at a power level of 800-W, the laser action reduced the modulus of rupture by 36-% in 6-seconds and by 82-% in 8-seconds.

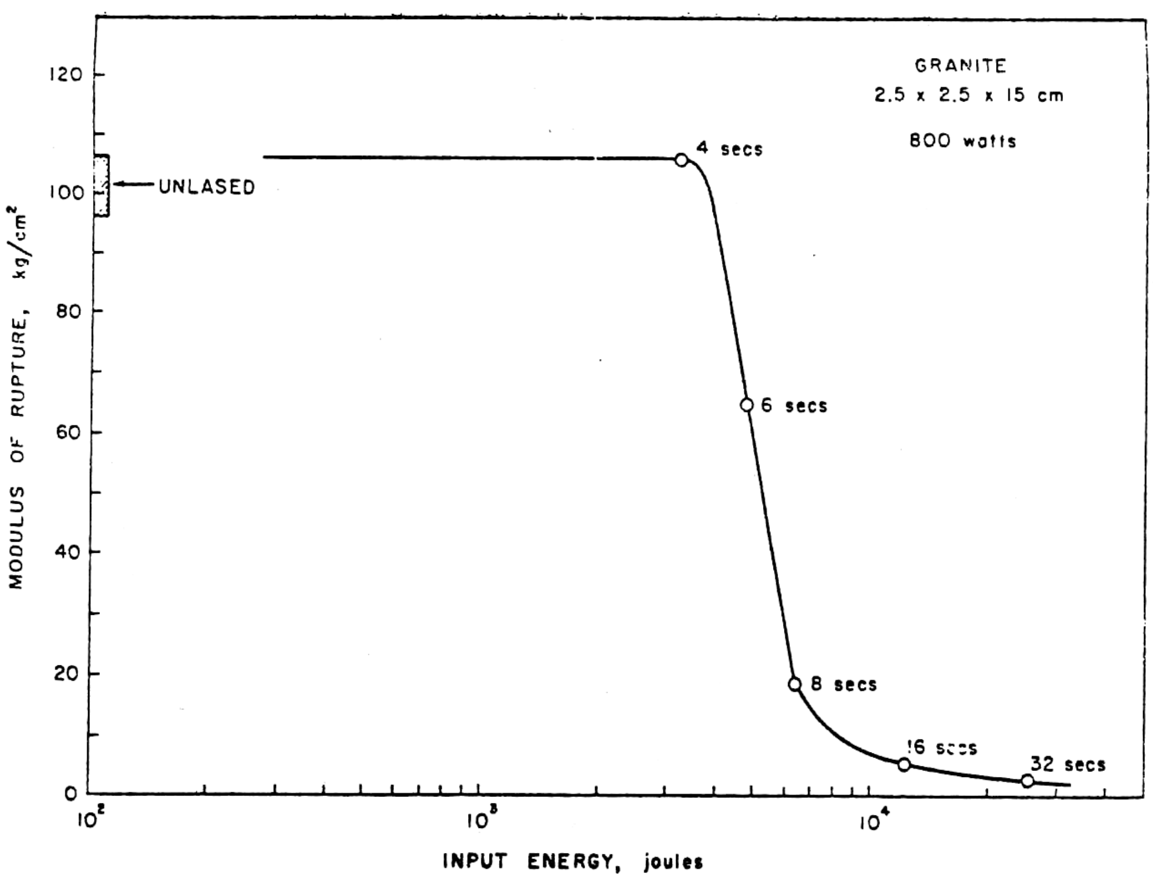


Figure 1.25: *Effect of laser energy on Modulus of Rupture of granite (Williamson)*

Williamson also conducted tests where power levels were varied from 0.4 to 2-kW. These tests indicated that rock thermal degradation was controlled by the energy input but no trend was observed with changes in laser power. Subsequent studies conducted with higher-powered lasers demonstrated that there was a relationship between rock thermal degradation with changes in the power used.

Moavanzadeh et al. (1969) [1.18] studied the impact on temperature of moving the sample in a radial direction away from the laser source. Using a 100-W laser, the investigation indicated that temperature decreased rapidly as the radial distance between the sample and laser increased. The temperature variation decreased from 340-°C to 0-°C over a radial distance of 1.4-cm.

Farra et al.[1.18] investigated the impact of laser-beams on the **Spalling** of rock. **Spalling** by definition is the physical process where a rock breaks up into small chips, flakes, or splinters. This phenomenon occurs on surface of materials when the material is subjected to sudden and significant changes in temperatures and/or pressures. With reference to the laser, the zone heated by the laser attempts to expand outward. The sudden nature of the lasing process inhibits the permeation of the heat out from the laser-source. Given that the heated expanding rock is confined by cooler rock, loosening/spalling of the rock occurs. To study the effects of spalling, Farra et al. applied laser beams on confined granite discs. A compressive stress of 104-MPa was measured at the center of the heated area at the time of the spall initiation. The compressive strength of granite however is approximately 234-MPa. Farra et al. attributed the failure of the sample below 234-MPa to the effect of the high temperature resulting from the application of the laser. Additional experiments by Farra et al. concerning laser-energy absorption indicated that for short duration tests of from 5 to 30 seconds, marble absorbed nearly 100-% of the incident laser energy and in another test involving a longer lasing time on a large granite block, Farra et al. found that the system attains steady state, i.e., heat loss due to conduction, convection and radiation equals the input laser energy. McGarry et al.[1.29] investigated the use of lasers for thermally degrading the rock-face that is ahead of tunnel cutters. He demonstrated that the extent of laser damage was dependent on factors such as laser power, laser-beam size, laser-beam traverse speed and patterns of heating. Also, he considered the case where the rock was permitted to cool prior to its cutting or drilling. Carstens et al.[1.43] replicated the experiments of McGarry et al. and quantified the results of the tests. The results of their investigations indicated that a 40-% increase was realized in the rate of tunneling machines.

Further, studies of the laser-rock interaction indicated that the incident energy of the laser is either *absorbed reflected* or *transmitted* through the material being lased. This is illustrated in Figure 1.24 and was confirmed by Zar.[1.42] Zar's investigations also demonstrated that the percentage of energy transmitted into the rock during lasing is reduced by the presence of vapor, which is generated during melting. This vapor absorbs a large percentage of the laser energy and consequently, the amount of energy available to continue melting of rock is reduced. Of the laser energy available, 5 to 10-% of it was used for melting of the rock and the remainder was absorbed by smoke and ionized gas. This problem was exacerbated as the depth penetrated increased and vapor was resident in the hole for longer periods of time. It can therefore be concluded that laser energy absorption by the rock is quite high and the process is efficient at the beginning (at the initiation of the hole). As lasing time increases (the hole deepens), other factors such as the presence of vapors evolve and reduce the process's efficiency.

Carstens et al.[1.44] and Jurewicz et al.[1.23] conducted investigations that agreed with the findings of Zar. Carstens et al. conducted experiments using a laser to cut kerfs. The traversing speeds were varied and the investigations demonstrated that higher efficiency was realized during early lasing times. Jurewicz's work where the traverse speed were varied, demonstrated that at lower traverse speeds, the laser cut deeper kerfs, but at higher traverse speeds the cutting process was more efficient.

Carstens also proved the importance of accurately focusing the laser on the rock. Carstens drilled a hole through a 10-cm block of trap rock. The hole that was drilled was uniform throughout its entire length. Carstens was able to demonstrate the importance of accurately focusing the laser. He subsequently concluded that the beam was refocused in the hole by reflection of the beam off the walls of the hole.

In later experiments conducted by Jurewicz, [1.21] he combined a laser and a radial saw to cut kerfs in Barre granite. He then broke the rock sample for the purpose of identifying the effects of each. His results demonstrated that the thermal degradation resulting from the lasing action enhanced mechanical breakage to an extent beyond that realized by using a saw.

McGarry[1.29] demonstrated that the load necessary to induce failure was dependent on the length of time between the lasing action and the application of the load necessary to induce fracturing. With time the temperature of the rock decreased and with this cooling, the load necessary to induce failure increased. The load necessary to induce fracturing immediately following lasing was 40,000-N as compared to 53,000-N after the sample cooled for 24-hours.

The research discussed above focused on the use of lasers in mining type applications. The next section deals with the work that has been undertaken concerning the use of the laser in oil and gas drilling applications.

1.5.5.1.2 Laser Drilling; as applied to the Oil & Gas Industry

At about the same time that investigations into the use of lasers for tunneling and mining purposes were ongoing, the upstream Petroleum industry began studies of its integration into drilling applications. The drilling process requires significant capital investment and much of this investment can be attributed to the costs associated with the amount of time required to drill, test and complete the well. A GRI study[1.57] conducted in 1990 indicated that 48-% of this time is spent in making a hole, 27-% of the time is spent on changing bits or placing/running tubular goods such as casing into the hole, and 25-% of the time is spent measuring well and formation characteristics. Technical developments in these related fields could reduce these costs.

The typical drilling operation during the 150-years since oil-well drilling began has seen significant changes. These changes include the replacement of the cable-tool method with the rotary drilling methods and improvements in materials used in tubular goods, drilling bits, and fluids used to cool the bit and transport drilled-cuttings to the surface. Fundamentally however, the hole-making process remains essentially the same, that is, mechanically induced failure of the rock.

The use of lasers as a replacement to these conventional systems has been considered and investigated. One of the early investigations into laser assisted drilling was conducted by Jurewicz et al. [1.22]. He proposed using the lasers for maintaining the gauge of the hole. An illustration of the system envisaged by them is shown on Figure1.26. They estimated that

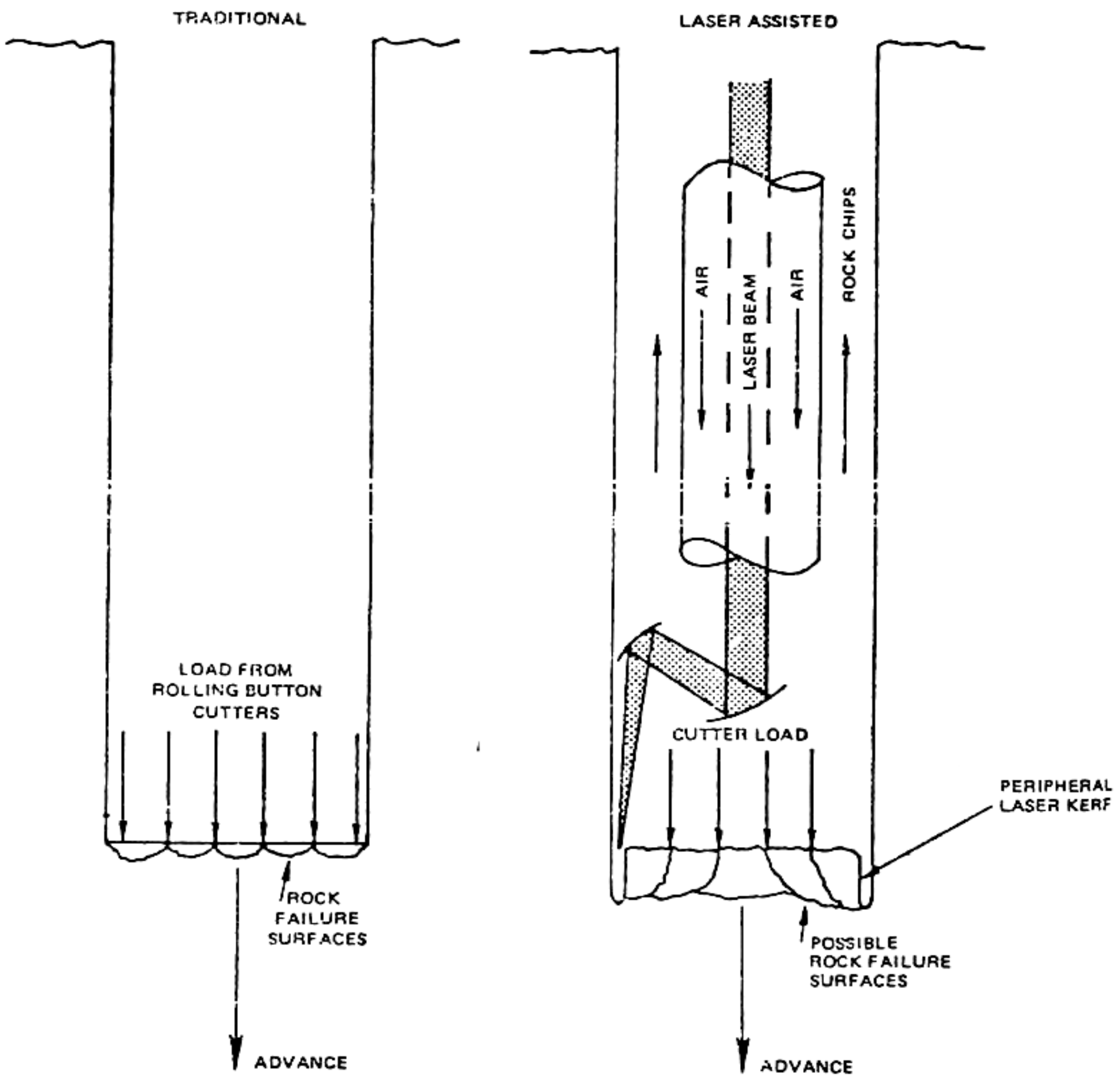


Figure 1.26: *Laser assisted Rock drilling*

a 50-kW laser would yield a three to six fold increase in the rate of penetration of a 0.3-m diameter bit rotating at 60-rpm in hard rock. It was concluded by them that the gauge resulting from the lasing weakened the rock and provided more efficient cutter load transfer to the rock surface and thereby increased the rate of rock destruction. However, no test data were provided.

Keenan[1.24, 1.25] patented a laser drill that operated by using drilling-mud displaced from the surface to rotate a turbine that would generate electricity to rotate a laser. The rotating laser disintegrates the rock over the circumference of the hole. He subsequently proposed a laser-sonic drill. In this case, the sonic energy is used to assist in fracturing of the rock and removing the rock-chips from the bottom-hole and also would assist in further breaking up the large rock fragments removed by the laser. Salisbury and Stiles[1.46] patented a similar mechanism that combined a pulsed laser-pulsed fluid system to drill oil wells. Pulsed lasers vaporize the annular area and pulsed fluids thermally shock and shatter rock cores. The vapor pressure created by the laser helps to move the rock cuttings to the surface. Shuck [1.36] in 1976 proposed to remove molten vaporize rock that is created by the laser action by providing high pressure gas that would force the molten and vaporized rock into fissures and pores surrounding the well bore. The concept envisaged significantly improved the efficiency of using the laser. This improved efficiency resulted from the removal of the melt and vapor that absorbs most of the useful laser energy from the path of the directed laser.

The practicality of using lasers for drilling was considered to be questionable given the economics of the process. Onsite studies indicated that a large specific energy was required to melt and vaporize the rock. To deliver large specific energy required high power lasers that at the time were unavailable. The available lasers generated large wavelengths, which are more difficult to focus. The efficient transmission of laser power from the laser source to the rock surface also presented another problem. The large physical size of the laser source presented questions concerning its portability and safety.
Without additional research into the parameters attendant to the operation of lasers and its effect(s) on the properties of rocks, it was concluded that it was unlikely that lasers would be the sole rock removal mechanism for field-scale drilling of rocks. Instead, the laser

could possibly be used to weaken the rock and thereby improve the performance of the mechanical cutters. These early studies were primarily focused on enhancing tunneling and were directed to applications for the mining industry. Many of these advances that were realized in laser technology did not appear in literature directed to the petroleum and natural gas industry. Consequently, the laser was not seen as a prospective tool for use in that industry. As recent as 1990, the GRI suggested that the use of the laser for oil/gas well drilling receive no further consideration. This conclusion was predicated on a review of the data/information obtained from tests conducted during the late 1960's and early 1970's. Since that time, significant advances have been realized in laser technology. Developments in the generation of laser power, in improved efficiency and portability, and in transmission capabilities have occurred. It was the decision by the U.S. Congress, in 1994, to make available the findings of the U.S. Department of Defense's Star Wars Projects that marked the beginning of a new era for laser development. The Star Wars Projects had boasted of developing high power, low wavelength tactical lasers for satellite warfare. The technologies associated with experimental laser weapons system was made available to the private sector for the purpose of promoting development of laser science for application to the industrial sector and other areas. The availability of these new laser technologies was crucial for the development of tools and processes that had application to the oil and gas business.

Organizations such as the Gas Research Institute (GRI) (now the Gas Technology Institute (GTI)) conducted investigations into the use of industrial lasers for applications to the oil and gas industry. The first study that was undertaken from 1997 to 2000, is entitled: "Adapting Star War's High Powered Lasers to drilling Natural Gas Wells," and as the title implies, examined the feasibility of applying extremely high powered military lasers to the drilling of oil and gas wells. This initial project focused on an extensive literature survey[1.47] that reviewed publications that dealt with laser-rock interaction and the latest innovations resulting from drilling research. It was concluded by the authors, R.M. Graves and D.G. O'Brien, that the laser had "potential" to significantly impact the drilling-process and could result in:

- Significant increases in ROP,

- Reductions in rig day rates, casing requirements, and trip-time and increases in bit -life,
- Enhancements in well control, perforations and stimulation,
- Environmentally safe and cost effective drilling and completion techniques

In a subsequent publication [1.53] that was predicated on their literature review, Graves and O'Brien indicated that only high-powered lasers would be practical for application in natural gas drilling and completion. Further, they identified seven types of lasers that had this potential:

- HF (DF) Laser: Wavelength (λ) = 2.6 to 4.2-µm; CW mode

  The U.S. Army's Mid-Infrared Advanced Chemical Laser (MIRACL) was the first laser to be used for tests on reservoir rocks.

- COIL Laser: Wavelength (λ) = 1.315-µm; CW mode

  The U.S. Air Force Research Lab's Chemical Oxygen Iodine Laser (COIL) was developed in 1977 and has matured into a sophisticated military accessory and has applicability to industry.

- CO_2 Laser: Wavelength (λ) = 10.6-µm; CW/RP mode

  Its advantage is significant durability and reliability; but its disadvantage is a large wavelength. Its average power output is up to 1-MW.

- CO Laser: Wavelength (λ) = 5 to 6-µm; CW/RP mode

  It can achieve an output power of up to 200-kW.

- Free Electron Laser (FEL) Laser:

This laser operates using high energy electrons that lack discrete energy levels; and therefore the tuning to virtually any wavelength in CW mode is realizable. Thus the possibilities for varied applications exist.

- Nd:YAG Laser: Wavelength (λ) = 1.06-μm

  An output power of 4 to 10-kW is achievable. It has many industrial applications.

- KrF (excimer) Laser: Wavelength (λ) = 0.248-μm; RP mode

  Average output power achievable is 10-kW.

Preliminary tests using a high-powered MIRACL demonstrated that lasers were effective for drilling. A R.O.P. of 450-ft/hr, which is 100 times faster than that realized, using conventional rotary drilling, was achieved. Areas for future research included:

- Studies that focused on interactions between rock-fluid systems and lasers; and systems that deliver the laser to a rock-face at the bottom of well;
- Analyses of lasers including laser-type, wavelength, mode of operation (CW or RP), power density and beam-profile.

The results of investigations that used a COIL high powered laser were reported by O'Brien et al.[1.54] located The laser used by O'Brien et al. was located at the U.S. Air Force Lab in New Mexico. These investigations demonstrated that a vitrified sheath was created during drilling over the circumference of the hole. The investigators suggested that this sheath could eliminate the need for concentric casing strings. Since the sheath is formed as the drilling takes place, there is little or no influx of formation fluid into the wellbore. Also the vitrified sheath acts to mitigate the damage resulting from movement of fluids into porous/permeable formations. Problems such as differential-pressure sticking and borehole swelling or collapse can also be avoided. By eliminating the need for concentric casing strings, the hole drilled with a laser is a single-diameter hole that extends from surface to total-depth. Savings are realized in both time and cost for drilling and completion.

O'Brien et al.[1.54] also indicated that the rate-of-penetration in the context of laser-drilling, is dependent on hole-size and power delivered to the laser. This is contrasted to the parameters used to qualify conventional rotary drilling such as weight-on-bit (WOB), mud-weight and rotary speed. The authors also suggested that to obtain the best results, a synergistic combination of both the conventional and laser technologies be used. Such a system could improve bit-life and reduce the number of pipe-trips into and out of the hole. It should be noted that a similar concept had been proposed by Jurewicz[1.21] for systems such as "Laser assisted Tunneling" and "Laser assisted Rock-Drill."

To identify the parameters that control the interaction between the laser and different types of rocks, a test matrix using six different kinds of rocks was constructed. The COIL laser penetrated all six of the rocks studied. Other observations made:

- There was no impact on ROP of changes in the composition of the atmosphere in which the tests were conducted,
- As the length of time during which the sandstone rock was subjected to laser action increased, the specific energy required to remove the next cubic cm of rock also increased,
- Lateral and vertical confining stresses had a minor effect on specific energy requirement,
- Any particular rock type definitely seemed to interact differently when acted upon with a pulsed or chopped beam. There was no trend observed that was persistent for all rock types.
- The presence of fluids in the sandstone-cores has only a small impact on the penetration-rate of a laser in a rock,
- Using a laser to vertically penetrate rocks is more difficult than using a laser to horizontally penetrate a rock.

B. Samih[1.52] published in his Ph D. thesis the results of experiments conducted using MIRACL and COIL lasers. His research focused on the analysis of high power laser-rock interaction and its effect on altering rock and fluid properties. The rocks used in the study were Berea yellow sandstone, Berea gray sandstone, Mesa Verde shaley-sandstone, shale, limestone, granite white and granite feldspar. Analyses were performed on the rock samples before and after lasing. Approximately 200 samples were lased using the COIL. The following observations were made:

- *Effect of laser power on ROP and Specific Energy in different rocks using fixed/constant lasing time*

  Other parameters that were found to affect ROP were bulk-density, percentage of quartz present in the rock sample, permeability, color and void space/porosity of the rocks. The author indicated that at low lasing power levels of 2 to 3-kW, increasing the laser power to 6-kW resulted in an increase in ROP and a decrease in SE. A review of the literature indicated that higher powered lasers require smaller lasing time given that peripheral effects, which increase SE, become evident. The MIRACL tests demonstrated that the use of higher powered lasers causes vaporization of the rock and consequently, there was no melted material observed. The presence of melted material results in the absorption of a large part of the laser energy. This effect was observable in all rock-types tested, but the extent of the effect varied.

- *Effect of Lasing time on ROP and SE using fixed power*

  Initially the rate of penetration increased with lasing time, but after 12-seconds the rate of penetration with increasing depth, decreased. Based on this observation, 12-seconds was taken to be the optimum lasing time for the experiment. The use of different rock-types and/or different laser types may result in different optimum lasing times.

- *Effect of lasing action on the permeability, porosity and elastic moduli of rock*

  The permeability of the unlased samples was measured using a Core Measurement System (CMS-300) and Pressure Decay Profile Permeameter (PDPK). Only the PDPK was used to measure permeability of lased rocks. The porosity of unlased samples was measured using four different methods:

volumetric, CMS-300, acoustics and thin-section analysis. The porosity of the lased samples was measured using acoustics and thin-section analysis. The elastic moduli (Young's modulus, Poisson's ratio, shear modulus, bulk modulus, bulk compressibility and combined modulus) were calculated using appropriate equations. Changes in absolute permeability, porosity and elastic moduli are dependant on thermal properties, mineralogy, density and melting temperature of the rock. Analyses demonstrated that lasing action improves the permeability and porosity of rocks but only to an extent that is dependant on rock type. This effect is attributed to development of macro and micro fractures within the rock marix and also the effect of temperature on the rock's mineralogy. The results of tests conducted with the MIRACL were similar. For tests conducted using sandstones, the Young's modulus, shear modulus, bulk modulus and combined modulus of the rock near the lased section were reduced. These changes in the moduli were less significant in tests conducted with limestone and shale. Poisson's ratio was also dependent on the lithology.

- *Effect of laser action on rock's phase behavior:*

  The temperature necessary to melt the rock samples was determined using Differential Thermal Analyses (DTA). On a theoretically basis, the melting temperatures were determined using correlation diagrams developed by Ehlers (1972). The phase change of the rock from the solid-state to a liquid-state was found to be dependent on the laser power level and the melting temperature of the minerals making up the rock sample. If the melting temperature of the rock was high, the failure of the rock with an increase in temperature is low. Also, the melting temperature was determined to be proportional to the percentage of quartz contained in the rock sample.

  Change in rock's absolute permeability, porosity and strength can be attributed to phase changes. Given the variability in phase behavior among rocks, the changes in these properties are different for each rock type. In the case of sandstone, shale and granite the section of the rock that was subjected to the lasing action was converted into a glass like material. By contrast, the lasing action on a limestone sample caused the rock to either vaporize or cause a change in composition.

The Scanning Electron Microscope combined with Energy dispersive System (SEM-EDS) was used to determine the permeability and the presence of fractures of the melted materials (sheath) that was created by the lasing action. The results demonstrated that the sheath surface was smooth and impermeable, and contained no fractures. These results suggest that this sheath has potential use as a replacement for casing in the wellbore.

- *Effect of laser action on the formation of fractures*

  There were several factors that were shown to impact the creation, extent, density and geometry of fractures that result from the lasing action on rock samples. These include:
  - Phase behavior, which is function of the mineralogy of the rock sample, may impact the creation/formation of fractures,
  - Shape and size of the rock sample tested affects the creation/formation of fractures,
  - Orientation of the stresses in the rock sample dictates the pattern of fractures,
  - Fractures are formed/created both during and following the lasing process. During the former, heat induced expansion of the rock provides the conditions necessary for the formation of fractures. During the latter, it is the contraction of the rock during cooling that causes the formation of fractures,
  - Fracture intensity increases along with the temperature gradient.

- *Effects of laser action on other parameters*
  - Comparison between the performance of chopped and continuous laser beams did not indicate any significant difference or unique trend. The effect on the behavior of SE was not consistent.

- o Fractures that were induced horizontally consumed more energy than those induced vertically. The difference in magnitude was small and was attributed to the pattern of plasma accumulation around the hole.
- o The value of SE was larger for samples saturated with liquids such as water or oil. The liquids contained within the pore-space of the rock tended to absorb lasing energy, which reduce that available for destruction of rock.
- o Stressed rocks consume more SE.

The thesis also contained several recommendations concerning the extension of this laboratory work to field applications and to the development of a prototype laser-rock drilling device. These recommendations include:

- Use of fiber optics to effectively/efficiently deliver laser-power downhole.
- Using a vacuum device to remove gases and vapors generated during the lasing action. This vacuum device could also be powered using the fiber optics system that is used to simultaneously power the laser-system.
- Using an optimum-pulsed laser that permits cooling of the melted material to form a uniform impermeable sheath. This impermeable sheath serves as a replacement for casing. Also the cooling time may be used to clear the hole of secondary expulsions.
- Designing an apparatus for testing the operation and performance of lasers in a variety of potential downhole environments.
- Designing multi-beam delivery systems for applications in well completions and for use in such procedures as perforating of casing and well stimulation.
- Designing systems that address issues such as removal/disposal of gases. Some of these gases may be toxic and proper disposal of them needs to be managed.

The second phase of the GTI / DOE investigations was entitled: Laser Drilling: Drilling with the Power of Light.[1.51] The DOE funded this phase of the research to fully investigate the basic results from the GRI study, which can be used to help advance this technology from the laboratory to its application by industry in drilling/completions of wells. The main objectives defined in this study:

1. Quantifying specific energy required to remove rock,
2. quantification/qualification of pulsed-lasers parameters,
3. laser-rock interaction in water saturated cores.

The report contained experimental data, results, discussion and outcomes of the research. The rock-types chosen for these investigations were Berea sandstone, Ratcliff limestone and Frontier shale. Similar rock-types were used in previous GRI research and were selected for the uniformity of their characteristics. The lasers available for this study were a 6-kW CO_2 laser that is capable of operating in both CW and super-pulsed modes; and a 1.6-Nd:YAG solid state laser that is capable of a wide range of pulse widths and repetition rates. The Nuvonyx laser was also tested using various rock-types. The Nuvonyx laser had the advantage of a compact size and consequently had use in downhole applications. In 2001, B.C. Gahan et al.[1.55] published a paper that discussed these investigations and focused on the interaction of high powered pulsed lasers and rock. The factors that affect the amount of absorbed energy transferred to the rocks were categorized as primary and secondary. The laser and rock parameters are defined as the primary factors. The others are secondary factors such as melted material, exsolved gases in the lased hole and induced fractures. For a given set of defined laser and rock parameters, there is a SE available; this assumes that there are no secondary factors impacting the lasing process. Also, the results show that initially SE increases with lasing time. As lasing time increases, the depth penetrated also increases and secondary effects come into play. A series of tests on different rock samples indicated that shale samples realized the lowest SE when compared to limestone and sandstone. SE was also found to decrease with an increase in both pulse repetition and pulse width. Pulse width was confirmed to be a more dominant factor in controlling SE. In the case of shale, rock removal was through spalling and melting. Figure 1.31 depicts a plot of SE versus average power. As the figure indicates, SE's minimum value is attained at the point prior to the onset of melting.

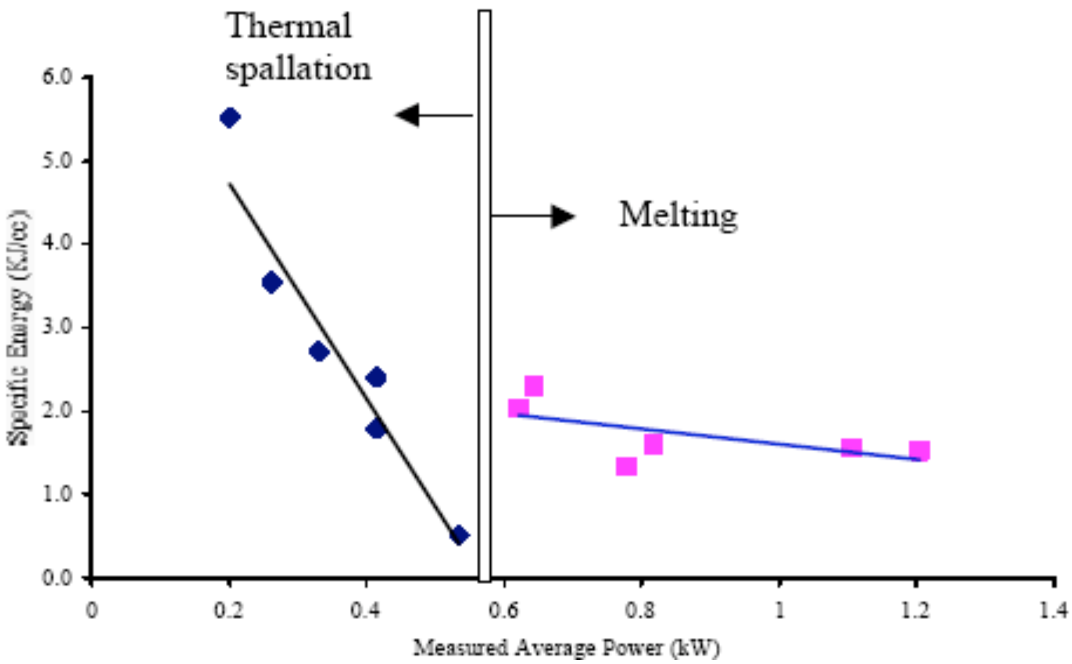


Fig.1.31: *Change of material removal method from spalling to melting*[1.55]

Additional aspects of this investigation were presented in a GTI / DOE report[1.50]. The points raised in this report were as follows:

- A series of tests were conducted where the power-density was varied along the length of test-samples of different lithologies. For each combination of peak power, pulse width and repetition rate, a region/zone of spalling was distinguishable. The power-density associated with that region/ zone was used as the starting point of the test matrix for each lithology.

- Initial tests under CW conditions used the CO_2 laser. These tests failed to provide a distinguishable spalling zone. As a consequence, the pulsing capabilities of the Nd:YAG laser were utilized to better control the laser parameters necessary to obtain the spalling zone.

- Limestone was the only lithology tested that had the same SE as predicted by previous GRI research. Hole building in limestone is accomplished through the thermal degradation of $CaCO_3$. This is contrasted to the failure mechanism attendant to sandstones and shales. In sandstones and shales, failure is achieved through the breaking of bonds between grains or crystals and consequently no melting and vaporization occurs. There are therefore in limestone no secondary effects present that impact SE.

- Thermal spallation in terms of SE is the most efficient rock removal mechanism given that it requires the lowest SE.

- Increasing beam repetition rate was found to be advantageous because of the increase in maximum temperature, thermal cycling frequency and intensity of laser-driven shock. These factors are referred to as the temperature factors.

As previously indicated, an objective of this phase of the GTI / DOE investigation was to test laser-rock interaction in core-samples that were water saturated and underwater. To accomplish this objective, the approach was to divide the project into stages:

- The first stage was to measure the energy absorbed by the water.
- The second stage involved adjustment of the beam parameters to account for energy loss realized through absorption.
- Using fiber-optics, directly lase the water contained within the core-sample to minimize reflective losses and to better simulate wellbore conditions where the hole contains standing water.

Only Berea sandstone samples were used in these investigations. The results of the tests were considered to be inconclusive. It was hypothesized however that two possible effects may be present. The first effect that was set forth suggested that the water present in the core would be explosively converted into steam. The near instantaneous formation of steam and the resulting spike in pressure induces stresses. These stresses can possibly result in breakage of the rock. The other possible effect is that the presence of water would increase the thermal conductivity of the sample. The increase in the thermal conductivity would enhance the dissipation of the laser energy away from the working surface thereby reducing cutting efficiency.

To simulate the presence of standing water and other fluids in the borehole, a series of tests were conducted for the purpose of obtaining qualitative results. To avoid surface reflections and instability, a fiber optic conduit was employed to deliver the beam to the submerged core sample. Preliminary tests indicated that approximately 3-percent of the beam energy was lost per centimeter of water thickness and dispersion of the beam was found to be 4-degrees. It was also determined that the position of the fiber relative to the rock face significantly impacted the results of the experiment. If the stand-off of the fiber optics relative to the core sample was comparatively large, energy was absorbed by the water and little or no energy was transferred to the rock-face. By contrast, if the stand-off of the fiber was comparatively small, the spot-size was decreased and a corresponding increase in the power density was realized. In this case, energy was transferred into the rock and melting resulted. Additional experiments were deemed necessary to optimize and quantify the position of the fiber to achieve rock spallation.

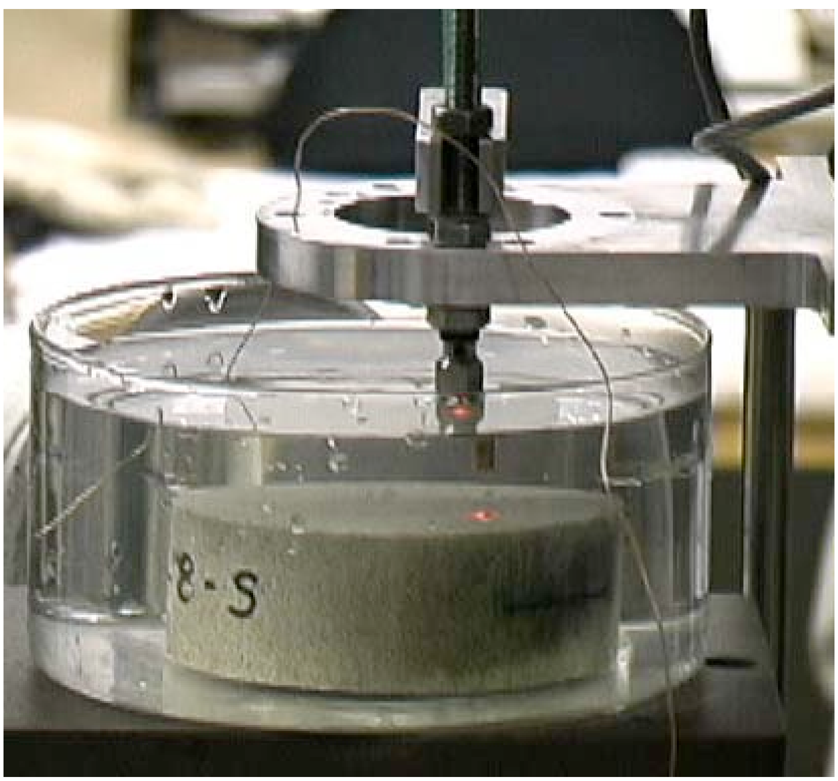


Fig. 1.35: *Apparatus for under water lasing*[1.51]

The results achieved in this phase of the research were useful and provided insight for subsequent investigations that were intended to eventually bring laser-drilling from the laboratory to the field. The research suggested would consider and address topics such as:

- The spalling region that exists prior to the melting region demonstrates the least SE. The location/position of this zone relative to the location/position of the laser needs to be quantified.
- The permeability around the lased hole should be evaluated since this would provide insight into its potential for use in completions.
- There are significant variations in the SE of shale between the spalling and melting regions. Since shale is typically encountered during drilling, evaluation of the lasing impact on different types of shales is necessary.
- Application of multiple laser beams could prove to be beneficial during the drilling of large diameter holes. The number of laser-beams needed and the attendant overlap requires study given that a smooth work face is the desired result.
- Tests to evaluate the effects of variations in confining stress, pore pressures and drilling fluids.

Other engineering studies that were recommended include:

- Delivery of high powered laser beams downhole using fiber optics. This recommendation is predicated on the efficiency of fiber optics in transmitting laser beams.
- Feasibility of using multiple beams for drilling holes of variable size.
- An assessment of available laser-types for use in this application.

The next phase of the study that was undertaken by the GTI / DOE research consortium was entitled the Application of High Powered Lasers to Drilling and Completing Deep Wells[1.63]. The objectives of this phase of the study were:

- Evaluate the feasibility of using beams to produce multiple spot holes.
- Continue the investigation of underwater lasing to clearly delineate the effects of the various parameters needed to produce an efficient drilled hole.
- Simulate the perforation process.

- Assess the dependency of specific energy on wavelength.

Berea sandstone was chosen for these experiments given its availability and consistency in composition, porosity and permeability. As the tests proceeded, limestone and shale were also tested to develop a range of values. The 6-kW CO_2 and a 1.6-kW Nd:YAG lasers used in these studies were located at the Argonne national Laboratory. The following sections contain a brief discussion of the results of these studies.

- *Using multiple spots to increase hole diameter*

Previous investigations indicated that the efficiency of laser drilling decreases drastically as the depth of penetration increases. Using a single spot and a longer lasing time had resulted in melting of the rock and the occurrence of other secondary effects. As a consequence, it was not possible to definitively state that a single beam could create a six or eight-inch deep hole. The alternative to be investigated was to test the use of beams to created multiple spots and in this way create a hole of the required diameter with a smooth work face. This investigation of this option was delineated into 4 stages:

- For single-spot lasing, evaluate the effect of varying relaxation time between bursts of energy on cutting efficiency.
- For single-spot lasing, evaluate the relationship between relaxation-time and number of bursts of energy to the onset of melting.
- Repeat these tests using multiple spots.
- Determine the overlap necessary to avoid the formation of ridges between the spots.

The Nd:YAG laser was used in these experiments. The rock types used were sandstone, shale and limestone. The laser-settings used were considered to be optimum with respect to each of the lithologies.

Figure 1.37 contains plots of the results for tests conducted with sandstone. These plots indicate that irrespective of the number of bursts of energy and the relaxation time used, the specific energy increased in the tests conducted.

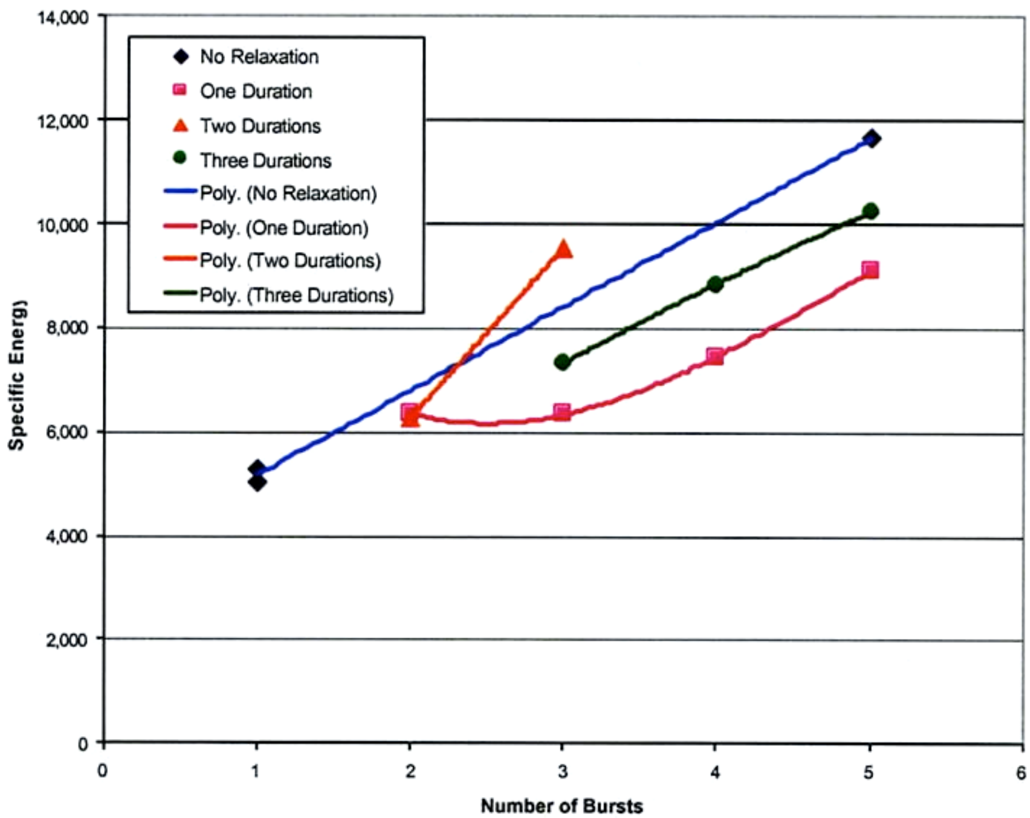


Fig.1.37: *Relaxation time comparison, Sandstone*[1.63]

Figure 1.38 contains plots for the tests conducted using shale. More melting was observed in these tests than those conducted using sandstone. Unique trends were seen for each of the three levels of power density used.

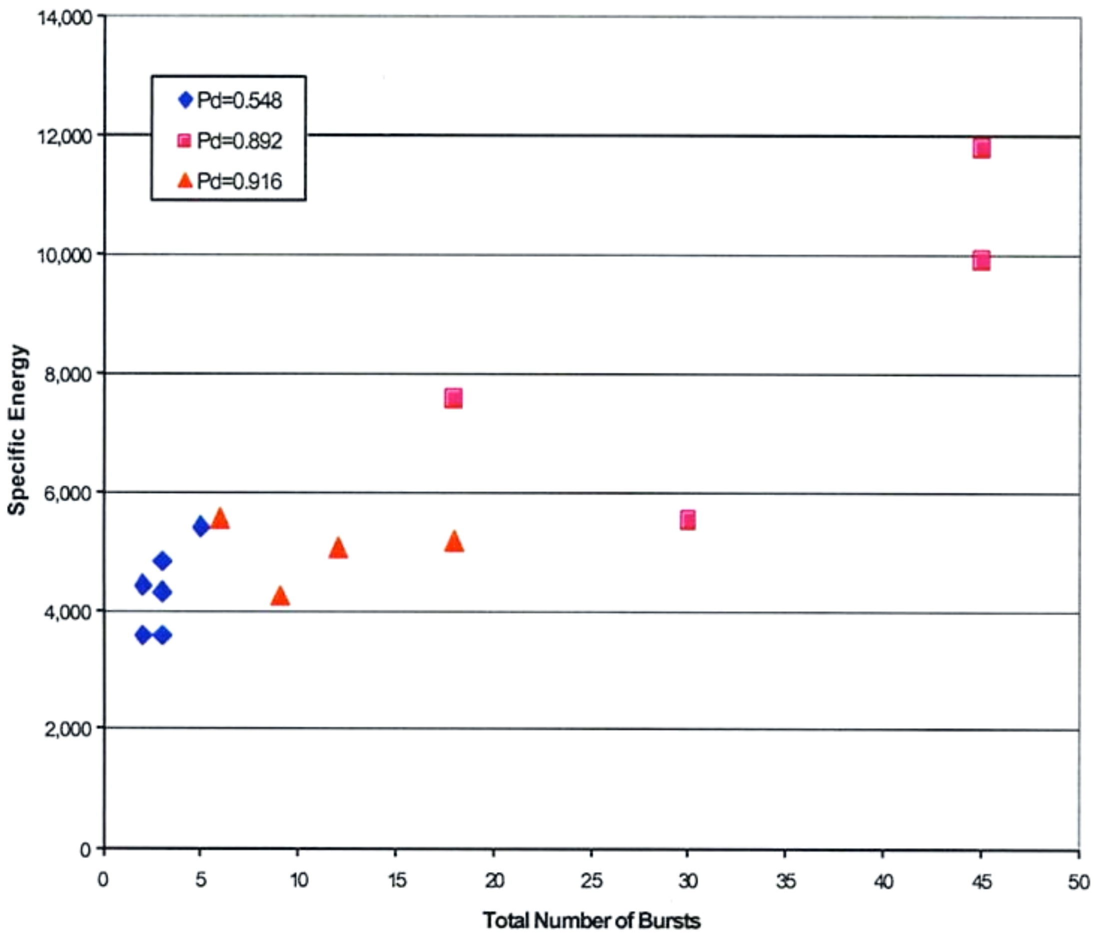


Fig.1.38: *Shale Repeated tests*[1.63]

In test conducted with limestone, the beam diameter of the Nd:YAG laser was set to 0.32 cm. This diameter is less than that used with the other rock types tested and was used to obtain higher power densities necessary to reach the spalling threshold of limestone. SE values reported were over 100,000 J/cc.

- *Multiple spot - repeated energy burst tests*

The focus of these tests was to evaluate the impacts of: (1.) varying the number of bursts of energy applied to the sample and (2) varying spacing between the spots. Spot patterns were designed for the multiple spot tests. The offsets used were based on the amount of overlap desired. The two offsets selected and tested were: 1.1-cm. and 1.0-cm. The 1.1-cm. and 1.0-cm. offsets resulted in 6-% and 10-% overlaps respectively. The triangular and parallelogram patterns were adopted for the tests and were predicated on the opinion that hexagonal close packing would provide the most efficient pattern for multi-spot cutting. Figure 1.39 illustrates the offset patterns used during these tests. Given the design of these multiple spot tests/experiments, the relaxation times between bursts of energy were longer than that realized in the single spot tests. Both the Nd:YAG and the CO_2 lasers were used in these studies.

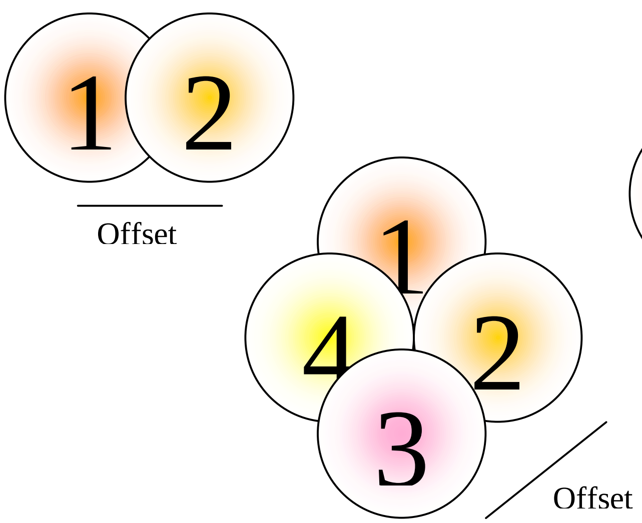


Fig.1.39: *Offset patterns tested*[1.63]

The results from these investigations were summarized in two publications[1.60,1.61] authored by Parker et al. These results were:

- Holes resulting from the multi-spot tests produced negligible melting, even though SE increased with the number of energy bursts applied to the sample.
- Increasing the relaxation time between energy bursts slowed the increase in SE with increasing number of energy bursts applied to the sample.
- Development of bridges between spots in the pattern was minor.
- The largest amount of rock was removed using the hexagonal offset pattern of spots.
- The holes narrowed with depth even though the laser beams were collimated.
- SE values were generally higher than any previous tests in the same parameter range.
- Limestone reacts effectively as desired to high power densities as long as depth is short with respect to beam diameter
- *Underwater laser testing of rocks samples in liquid:*

To simulate downhole conditions, experiments to test the interaction of lasers with liquids such as water, drilling mud and oil were planned. Two objectives were set forth for these tests:

- Understand laser attenuation through water.
- Determine the most efficient laser parameters to drill under water.

The two types of lasers used in these experiments were the 6-kW CO_2 laser and the 1.6-kW Nd:YAG laser. 4 rock types were used in these experiments: sandstone, mudstone, shale and limestone. Two configurations were used to address the objective of studying laser attenuation through water. The configurations were: (1) standing free water over a submerged rock sample, and (2) water jet flowing over the top of the rock sample. The configurations are illustrated in Figure 1.42.

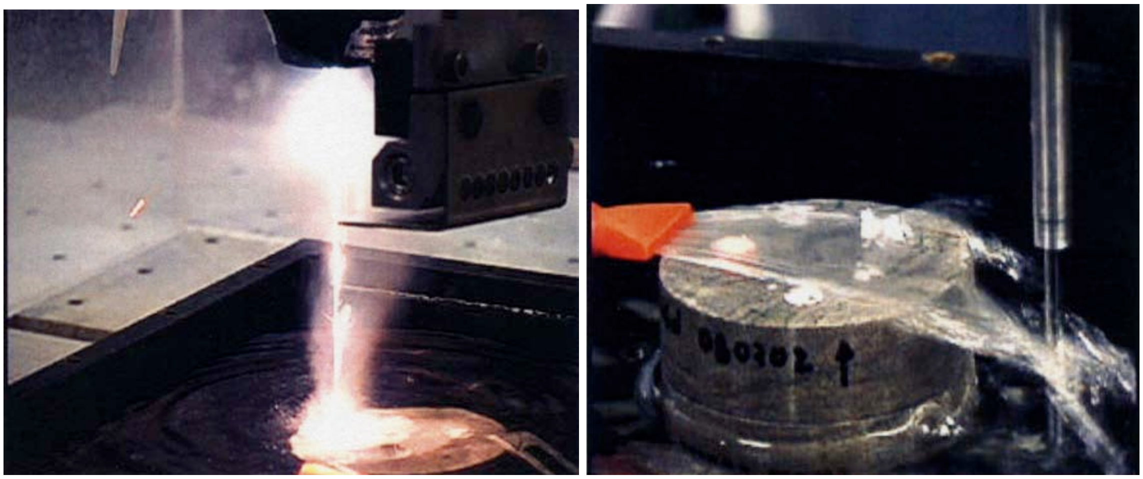


Fig.1.42: *Two test configurations – free water over submerged rock (left) and water jet flowing over top of rock (right)* [1.63]

The results of the tests conducted with free water over the submerged rock indicated that as the water deepened, the diameter of the lased hole decreased. These results are illustrated on Figure 1.43 and indicate that this trend is common to all rock types. The

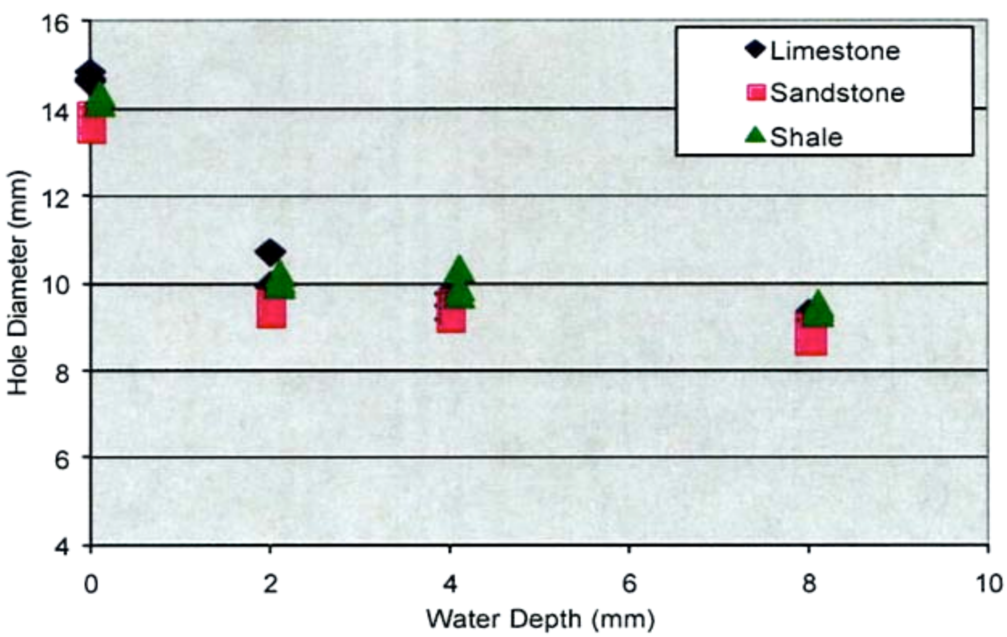


Fig.1.43: *Hole diameter as a function of water depth – limestone, sandstone and shale*[1.63]
Nd:YAG Laser

reduction in hole diameter is attributed to reduced laser power reaching the rock face. This reduction in power was attributed to factors such as absorption of the energy by the water and reflection by the water of the laser energy.

In tests conducted where the water jet flowed over the top of the rock sample. The pulsed beam penetrated through the 2-mm thick water jet and produced a slight hole in 1 second. The laser rock interaction produced gases and particles which hinder in the path of the laser. Rapid melting was observed at the surface. Low pressure flowing water was unable to remove the melted rock from the hole. Hence purging is definitely required when lasing with Nd:YAG laser

Water jet flowing over the top of the rock

CO_2 Laser

Water jet flowing over the top of the rock

The action of laser created a lot of steam as soon as it hit the flowing water jet. Water is almost opaque to the CO_2 laser. Therefore the CO_2 beam had to vaporize the water to pass through it. Once the laser beam forms a tunnel through the water it can affect the rock for drilling. But in this test the water jet continuously brought fresh water onto the surface and therefore it wasn’t possible to cause any effect on the rock using this laser.

Several laser energy attenuation sources were addressed for further design purposes. Optical and thermo physical properties of water were studies to better understand its absorption coefficient and how it causes different results for different lasers. Better underwater purging mechanisms will help in reducing molted rock in the hole an also other gases and materials that hinder the path of the laser.

3. Applications of High Power Lasers for Perforated Completions:

Perforating is the process of creating a communication tunnel from the casing or liner into the reservoir formation, through which oil or gas is produced. The most common method uses jet perforating guns equipped with shaped explosive charges. However, other perforating methods include bullet perforating, abrasive jetting or high-pressure fluid jetting. The present technology available has some disadvantages:

- Lack of control of hole size and shape.
- Reduction of permeability of perforated rock

With the ability of high powered lasers it has been proved that they can successfully drill into the rock. The ranges of parameters that can be controlled help define the desired size and shapes of rocks. Three test configurations are designed to analyze the possibility of laser perforation.

a. Fixed Beam test.
b. Circular motion Beam test.
c. Rotary rock test.

a. Fixed Beam test:

For the first test, a 1 inch defocused beam was pointed at a shale sample, 3 inch thick and 3 inch in diameter. The laser used was a 400 W CO_2 laser with nitrogen purging mechanisms. 4 bursts with duration of 4 seconds were applied to the center of the rock surface. The first 3 bursts drilled a hole 2.9 inch deep but the 4^{th} burst only melted the material.

Hence it is necessary to design a purging system that can have gas pressures high enough and efficient to remove all traces of melted material for depths more than 2.9 inches. A co-axial purging system was recommended for a better and much deeper hole.

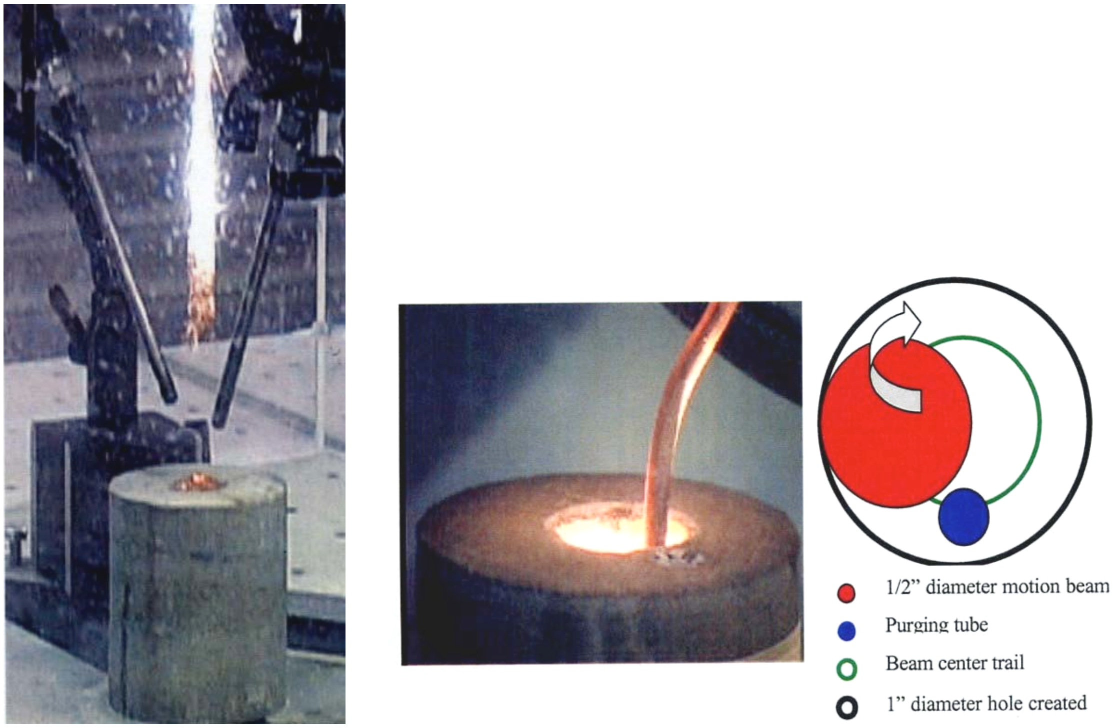


Fig. 1.44: *Fixed Beam test (left) and Circular Motion Beam test (right)* [1.63]

b. Circular motion Beam test:

In this configuration, the rock sample was moved circularly by the workstation under the fixed vertical beam and purge gas. This generated a relative circular motion of a defocused beam of 0.5 inch in diameter. The circling beam thus created a 1 inch diameter hole after one revolution. Purging system was height adjustable for better purging with lasing depth. A 4 inch diameter by 6 inch thick limestone sample was acted upon by a 4000 W CO_2 laser. One burst here is defined as one complete revolution of the laser. A 1 inch diameter hole, 5 inch deep was created. The hole was cone shaped.

c. Rotary rock test:

This configuration was a modified form of the circular motion beam test. As the relative position of the beam and purging gas changed throughout the revolution in the previous test, the rotary rock test was introduced. In this test the core rock is clamped and rotated about its own axis. A CO_2 laser was used at to power levels – 4000 and 2500 W. four different rotary speeds were tested – 10 000, 5 000, 3 000 and 2 000 degree/minute.

Lower speeds seem to have intensely melted the rock and formed a glass phase. Increasing the rotary speed reduced the melting at fixed power.

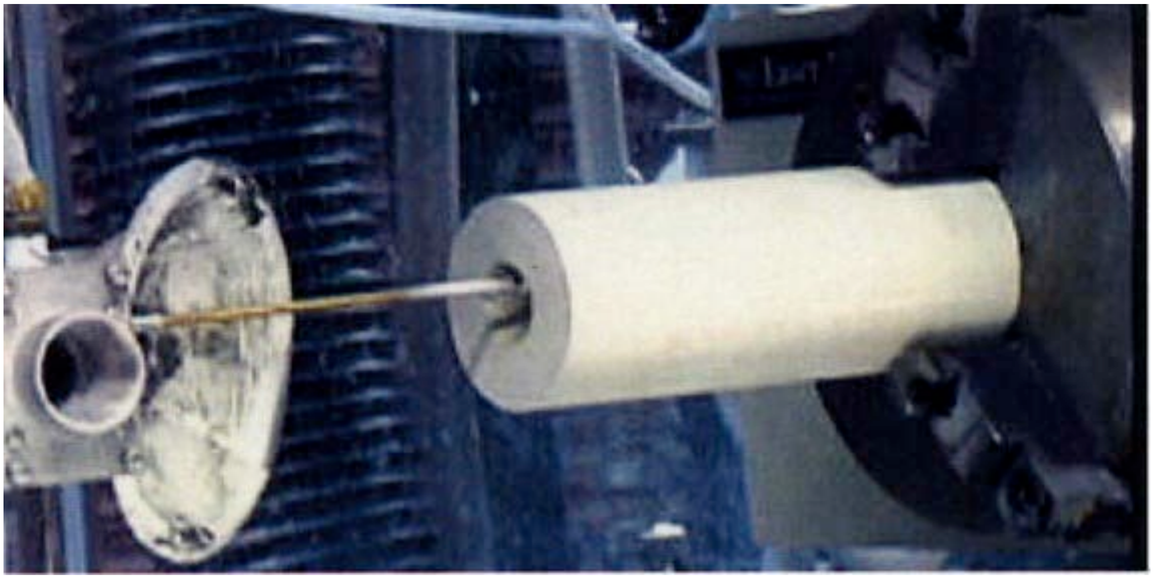


Fig.1.45: *A rotary rock test in progress*[1.63]

The conclusion noted from all experiments was that good clean holes were drilled for up to a certain depth after which melting occurred. Additional lasing did little or caused fractures in the sample. Hole tapering was also noticed. Efficient purging mechanisms should be designed. Also it was recommended that large rock samples as big as a foot cube should be used for perforation tests to avoid the edge effects and fractures. Collimated beams should be applied instead of a defocused beam.

The positive results that were obtained following the review and experiments on applying laser energy for perforating rocks, a research team led by GTI demonstrated closer results that proved the same. The authors believed that photonic energy could create fluid communication channels from the reservoir to the wellbore and at the same time enhance the permeability and porosity within and around the tunnel. High power laser beams were applied to the 3 common oil lithologies – sandstone, shale and limestone. The results were discussed in an SPE paper.

Well Perforation using High Power Lasers

Graves, R.M., Batarseh, S., Gahan, B., Parker, R.A

SPE 84418, 2003

The experiment constituted of applying laser energy to a grid pattern rock sample from which acoustic velocity and permeability measurements from in and around the perforated tunnel were taken. Rock mineralogy and rock properties were analyzed before and after the test. The two lasers used in these experiments were the COIL and MIRCL lasers.

After analyzing the results with respect to rock properties and mineralogy, it was clear that the effect of laser energy is measured by the amount of heat transferred to the rock sample. A higher rock thermal conductivity resulted in wider range of temperature distribution. Mineralogy differences like clays or quartz define differences in behavior of rocks towards laser energy though both of them enhance the permeability and porosity. Presence of lesser void spaces develops cracks, having no space to expand. Another parameter that was used as an index to measure perforation performance was Core Flow Efficiency (CFE).

$$CFE = \frac{k_p}{k_i} \tag{1.4}$$

Where,

k_p = effective permeability of penetrated zone

k_i = ideal permeability of undamaged zone

There was a significant increase in CFE in the tunnel itself as compared to the CFE range from conventional perforation techniques. Overall, it was realized that high power lasers improved rock porosity ad permeability in the perforated zone and in the adjacent zone (171% permeability increase in sandstone). Effects on rocks depended on rock mineralogy and properties. The results from perforating a block of sandstone revealed a clean tunnel without debris or any fine particles. The size, shape, length and angle of the shot can be controlled by changing the laser parameters and a desired hole specification can be achieved. As predicted by the authors, the use of photonic energy produced a clear hole with no perforating material leftovers and enhancement of desired rock properties.

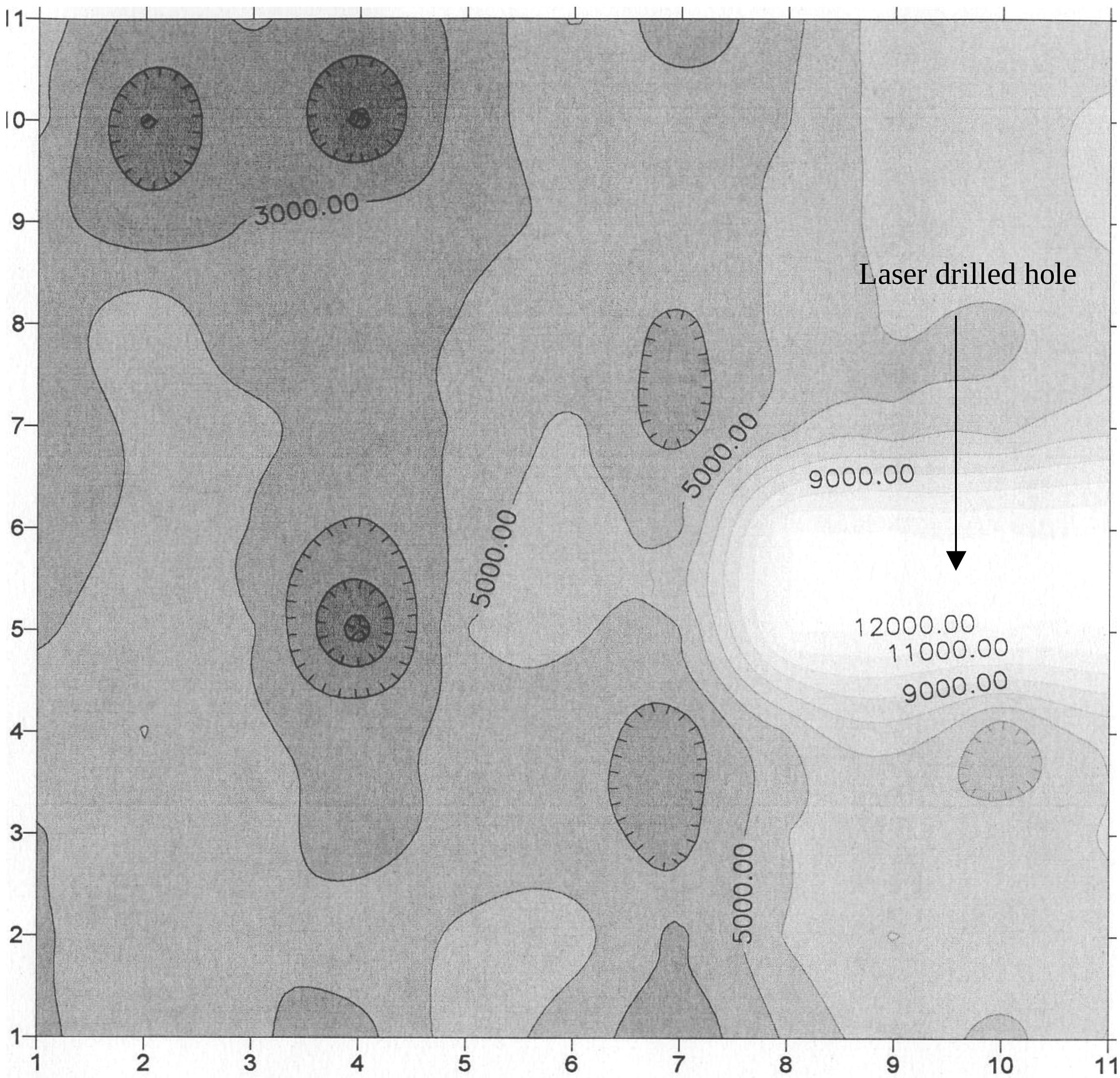


Fig.1.46: *Contour map showing permeability increase in the perforated tunnel and the adjacent areas*[1.66]

With the advent of high power fiber lasers in 2002 into the industrial field, GTI planned to perform a set of experiments using a 5.34 kW Ytterbium fiber laser. There were many advantages using the fiber laser with respect to any other laser. Fiber lasers can be efficiently delivered via fiber optics to targets downhole. This trait could be used for onsite applications in well construction and completions. Fiber lasers offered greater wall plug efficiency, better beam quality, increased mobility and essentially maintenance free operations over their lifetime. Since we have already learned that laser perforations are far better than conventional perforating techniques, this technology could enhance production rates and boost economic returns.

Later on, GTI conducted two sets of experiments which were explained in two different papers:

1. Deep hole Penetration of Rock for Oil Production Using Ytterbium Fiber Laser
2. Analysis of Efficient High-Power Lasers for Well Perforation

Deep hole Penetration of Rock for Oil Production Using Ytterbium Fiber Laser

Batarseh, S., Gahan, B., Sharma, B.C., Gowelly, S.I

SPIE 5448-98, 2004

Since this was the first test using the fiber lasers, various parameters affecting the deep hole penetration were examined. Though the results exhibited patterns effects were different for different lithologies. A list of conclusions followed from the experiments.

1. Method of purging greatly affects the depth of penetration and removal of by products. For limestone, air amplifier or nozzles, both had the same effect while nozzles were more efficient for sandstones.
2. Minimum specific energy was noticed with 8.9 mm beam diameter.
3. Increased pulsation frequency above 100 Hz caused no increase in depth penetration rate.
4. A trend was observed between Specific Energy and lasing time. Similar to trends observed for previous lasers, increased lasing time resulted in higher SE values.
5. Optimum average power for drilling holes in Berea sandstone with this laser was 3.2 kW.

Analysis of Efficient High-Power Lasers for Well Perforation

Batarseh, S., Gahan, B., Sharma, B.C., Gowelly, S.I

SPE 90661, 2004

Given the technical and practical advantages of fiber lasers over other high powered lasers, and desired results produced from previous experiments, GTI demonstrated another experiment to explore its possibility in well perforation applications. A one foot cube of Berea was chosen to be lased by the Ytterbium Fiber laser. The idea was to check if the beam was able to fully penetrate the whole block. The experimental objectives were to:

1. Create a simulated perforation tunnel fully penetrating the one foot cube of Berea Sandstone.
2. Minimize the SE values and keep them so along the experiment.
3. Prevent any sort of secondary mechanisms that would hinder the lasing efficiency.

A 12 inch hole through the sample block was successfully created by the fiber laser. The diameter was found to be 2.0 inches on both faces but decreased to 1.1 inches at the middle of the tunnel. This can be attributed to the lack of efficient purging mechanism. The purging set up was not designed to move forward linearly with the advance of the hole. The SE value observed for the whole process was found to be 5.5 kJ/cc, which was the lowest SE value for any laser source previously investigated.

Apart from the lower SE, the required power input for the system was relatively lower. Evaluation of rock properties proved that low power applications can create a narrower thermal deformation zone than military lasers. Deformation zones ranged to as far as only 2mm radially from the tunnel wall. This can be ascribed to the Berea's low thermal conductivity. There was no mineral melt observed at the tunnel walls. Permeability enhancement was observed in the adjacent areas of the tunnel walls. A MIRACL laser was evaluated for the same experiment. Though there was a high energy transfer for perforation, SE value was significantly huge and moreover it was unable to perforate the whole length of the block.

4. Wavelength dependence of Specific Energy:

One of the aspects that have to be considered in order to develop a laser drilling system is to test the dependency of rock cutting efficiency on the change in wavelength. For this purpose the Nd:YAG laser and the CO_2 laser were compared trying to match their parameters so that wavelength is the only variable. Tests were conducted on limestone sandstone and shale. Final results conclude that there is not much difference in rock volume removed per total energy density between the lasers. Samples with lower energy input (shorter exposure times) show noticeable difference with Nd:YAG removing less material. But at higher energy inputs there is no clear difference.

Appendix: Laser drilling and other conventional drilling practices

At the end of this phase an analytical study was carried out to better compare the laser technique towards other drilling mechanisms. To be able to do so data generated had to be converted to like terms of other drilling practices. The terms that best describe each mechanism were Rate of Penetration (ROP) and Cost per Foot. The former characteristic value could be easily denoted from experiments but the cost per foot for laser drilling was not calculable as capital investment and expendable costs were and are still unknown. This study provides estimates of ROPs using the repeated spot and multiple spot data generated from the previous experiments.

Prior to this study an effort was made to compare the specific energies of High power lasers and other drilling methods. A few of the authors involved in this report had defined specific energy as the measure of drilling performance that could be compared. The results from that attempt were published in an SPE paper.

Comparison of Specific Energy between Drilling With High Power Lasers and Other Drilling Methods

Graves, R.M., Araya, A., Gahan, B.C., Parker, R.A

SPE 77627, 2002

Specific energy calculations were made from experiments conducted on Berea sandstone. Laboratory measurements were taken for 4 different lasers –CO Laser, COIL, CO_2 Laser and Nd:YAG Laser. After careful analysis it was found that there was a confusing concept related to Specific Energy. What was considered as SE for the laser experiments was supposedly defined as Specific Kerfing Energies (SKE). Maurer defined SKE:

$$SKE = \frac{Energy}{KerfArea} = \frac{Power}{KerfDepth \times TraverseSpeed}$$

Moreover, review of the published work showed that the comparisons made in literature did not take into consideration factors like laser parameters, rock size and shape. Laser parameters that were found to affect the results were mentioned as laser wavelength, lasing time, mode of beam delivery etc. Figures and tables were provided in support of the conclusions. Also there were rock size factors that could have affected the results.

It was recommended that care must be observed when comparing SE values between laser drilling and other drilling techniques. Because of the amount of variables involved in laser drilling, simulations must be carried out only for the laser and rock parameters that best influence the rock.

Hence it was decided to compare the ROPs of different drilling practices to experimental ROPs caused by laser drilling. The method used here was to obtain the SE from literature and determine a ROP consistent with the assumptions that had to be made.

Basic assumptions were made towards *Rig Design, Laser Type, Optical Fibers* and *Rock characteristics.* A hexagonal pattern of lenses was assumed to best promote a circular hole. A degree of overlap was controlled to give the best shape. Downhole conditions were ranged from *Best Case, Most Likely* to *Worst Case*. Complete data, tables and figures can be found in the Report.

The results obtained were regarded as strictly first hand approximations. Having no knowledge on the conditions of the bottom of the hole and other laser drilling parameters, bold conclusions cannot be made. The final results proved very encouraging as the tests showed that ROPs were comparable to conventional drilling techniques.

1.5.5.2 Laser Technology to treat Asphaltene deposition in formations[1.81, 1.82]

Most crude oils, irrespective of their formation location or depth contain Asphaltene. Due to thermodynamic changes that arise at the neighborhood of wellbore, one can observe Asphaltene-plugging resulting in formation damage. This deposition leads to production losses. Moreover the treatment of these deposits is expensive and environmentally unfriendly. To deal with these tasks experimentalists have come up with novel techniques for cleaning Asphaltene with laser energy. Such procedures can be used at field sites to disrupt and disaggregate Asphaltene from the vicinity of the wellbore.

A Novel Technique for Treating Asphaltene Deposition Using Laser Technology[1.81]
Zekri, Abdulrazag, Y., Shedid, A. Shedid, AlKashef H.
SPE 70050, 2001

The authors proposed laser diode modules to perform these experiments. A 2-inch column of bitumen/powdered limestone mixture was placed on top of a powdered limestone column in a flow cell, and the flow rates were measured before and after the laser treatment. The rate was correlated with permeability of this powdered limestone column in absence of bitumen. A second series of experiments simulated more of the downhole conditions. Actual consolidated limestone cores were subjected to flow of Asphaltene crude. Damage was assessed and laser treatment was carried. Various laser intensities and time intervals were utilized to find optimum combination.

The experiments proved that the laser treatment could be used to clean Asphaltene from the porous media. Laser treatment produced 12.5% increase in the permeability of the core. The laser treatment however did not treat the Asphaltene completely. The rapid penetration of laser energy into the rock alters the thermodynamic conditions of the deposits. However, the simultaneous pumping is required to avoid the re-precipitation of the disrupted Asphaltene.

After a matrix of experiments it is concluded that higher the permeability and porosity of the system, the better treatment results are obtained. This proves that laser energy is much efficient by contacting the deposit rather than heating the rock. High intensity lasers perform better as they alter the thermodynamics of the rock causing re-dissolving of the Asphaltene back into the liquid phase. Ultra high laser energy also agreed to the same result.

Another set of experiments proved that there exists an optimum exposure time beyond which no additional improvement on the damaged core permeability was observed. More experiments are necessary before this technique can actually used on the field.

The authors also mention conventional techniques that are employed to treat deposits.

1.5.6 Optical Fibers: High Power Laser transmission

For material processing, or surface treatments the output of the laser must be focused onto the material surface. Conventional beam delivery systems utilize lenses and mirrors to accomplish this purpose. Specifically, the following elements are used:

- An upcollimator is used to increase the size of the beam, and reduce its divergence
- One or more mirrors are used to direct the beam towards the material
- An objective lens focuses the beam onto the sample

The involvement of all these apparatus in the system and their strict alignment poses a lot of disadvantages for any working application. The difficulties stem from a basic characteristic of all lasers - divergence. As a laser beam travels through space, it diverges. This divergence or expansion of the beam causes two difficulties.

Firstly, for delivery over long distances, the beam can become very large, requiring commensurate increases in the diameters of the optical elements. In the case of the objective lens, increasing the diameter limits the minimum focal length, and may introduce aberrations in the optical performance. Both of these factors increase the minimum focused spot size. Secondly, as the distance between the laser and the objective lens changes, the focused spot size also changes. The only way to maintain a constant spot size is to keep the optics fixed, and move the material. For large objects, this may be difficult and in cases of oil drilling or mining purposes this is outright impossible.

In addition to the problems caused by the laser beam divergence, conventional beam delivery systems are rather inflexible. Changing the relative positions of any of the elements can cause misalignment problems, especially if any rotations are required (such as welding or cutting contour surfaces). For these applications, delivery of the laser radiation through a flexible optical system is highly desirable.

Ideal characteristics of this system[1.85] include:

- Constant beam diameter over a range of distances
- Flexibility (position and orientation) in positioning the focused spot
- Complete enclosure of the beam, for safety reasons.

For these applications, optical fiber technology holds high promise: An optic fiber is a component meant to transport large amounts of information, and do it fast. Optical fibers are usually very thin and made of glass. The transmission employs laser light being led in a material with a higher index of refraction than the surrounding. The fact that the light is transported in the fiber and do not just leak out is due to total internal reflection. When light is refracted in a surface, and comes from a medium with higher index than the one it is going to, it is reflected instead of refracted is the angle of incidence is sufficient – Snell’s Law.

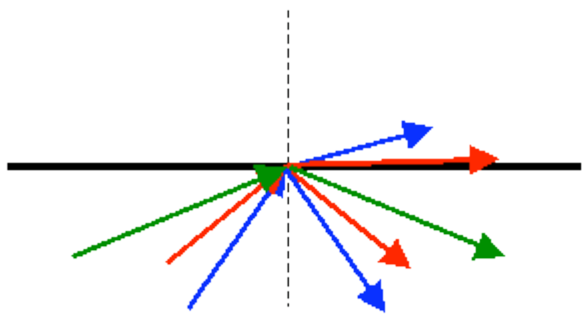
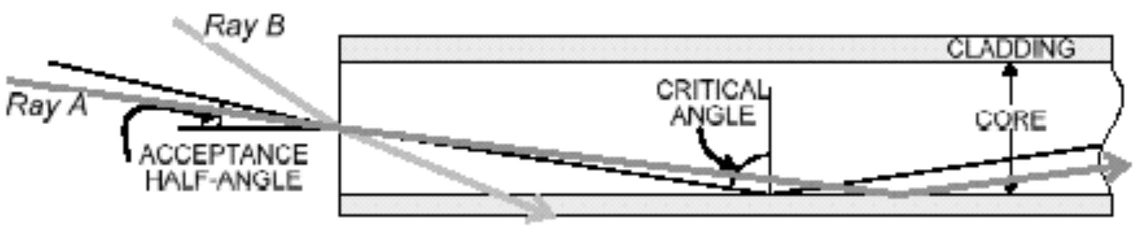


Fig.1.47: *Phenomena of total internal reflection*[1.85]

In the Fig.1.47, the red ray is refracted almost 90°. For greater angles of incidence, such as the green ray, all the light will be reflected. The idea is to make a thread of a material with high index (core) and surround it with a material with lower index (cladding). The fiber will then lead light even if it is slightly bent or twisted

An optical fiber (Figure 1.48) consists of two concentric layers: a core surrounded by a cladding. The core and cladding are typically both fused silica, but with slightly different indices of refraction. This construction allows light traveling through the core at less than a critical angle to be totally reflected whenever it hits the core-clad interface. This "total internal reflection" allows the beam to be propagated along the length of the fiber, with all of the beam energy contained within the core. A typical optical fiber used to deliver laser radiation has a core diameter of 400 μm to 1000 μm, and a cladding diameter of 1100 μm. The fiber is typically enclosed in an armor jacket (diameter 8 mm) to protect it from damage. Typical indices of refraction are 1.457 for the core, 1.440 for the cladding. These values result in a critical angle of about 81.2°. This in turn means that rays striking the end of the fiber at an angle of 12.8° or less will be propagated. This angle is often referred to as the acceptance half angle. The acceptance half-angle of the fiber is often expressed in terms of numerical aperture (NA), which is the sin of the angle. For this fiber, the NA is sin (12.8°), or 0.22. To avoid confusion, it should be noted that the critical angle (which is referenced to the surface normal of the core-clad interface) is a minimum angle for total internal reflection, while the acceptance angle (which is referenced to the surface normal of the fiber end face) is a maximum angle.



Ray A, within acceptance angle, experiences total internal reflection
Ray B, outside acceptance angle, leaks into the cladding

Fig.1.48: *A section of an optic fiber*[1.84]

1.5.6.1 Fiber Optic Beam Delivery Systems

A Fiber Optic Beam Delivery (FOBD) System[1.84] includes more than the optical fiber. As we can notice in the figure below, the system includes three additional subsystems:

- Input Coupling Optics
- Fiber End Connections
- Output Coupling Optics

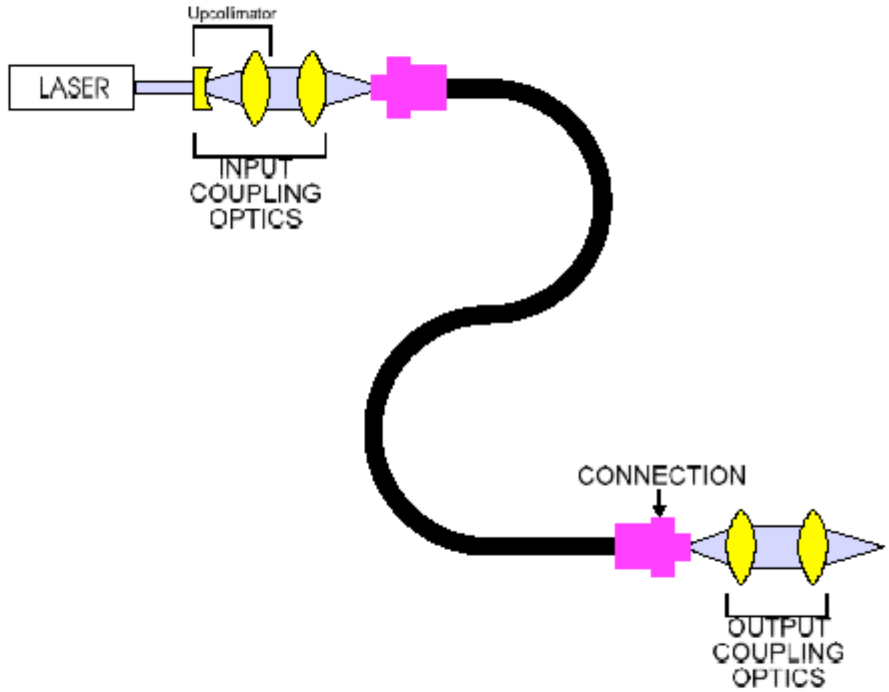


Fig.1.49: *Fiber Optic Beam Delivery System*[1.84]

Input Coupling Optics: The purpose of this optical assembly is to couple the energy from the laser into the core of the fiber. The input coupling optics generally include an upcollimator (which expands the laser beam), and a focusing lens assembly, which focuses the beam into the fiber. To function properly, the system must meet the following criteria:

- All of the energy must be focused into the core of the fiber. Energy that is focused into the cladding or outside of the fiber can cause catastrophic failure near the end of the fiber, especially at high power levels. Therefore, the diameter of the focused spot must be smaller than the core diameter of the fiber, and the spot must be aligned to the center of the core.
- None of the energy can arrive at an angle greater than the acceptance angle of the fiber. Any energy arriving at a greater angle will not be completely reflected at the first core-clad intersection; the energy escaping into the cladding will be lost, and may also cause catastrophic failure. Therefore, the cone angle of the input beam (determined by the size of the beam at the focusing lens, and the focal length of the lens) must be less than the acceptance angle of the fiber.

Fiber End Connections: The fiber end connections serve several purposes. They are:

- Since the fiber core diameter and the size of the focused spot are quite small (< 1 mm), alignment and stability are critical, if catastrophic failure is to be avoided. At the same time, easy replacement of fibers is required, ideally without the need for realignment. A properly designed connector accomplishes both.
- At a glass-to-air interface (such as the end of the fiber), a percentage of the laser power can be reflected from the surface (this reflection is also referred to as Fresnel losses). Typically, the reflected power is about 4% of the incident power (for 2000 watts input, about 80 watts is reflected). The connection system must be capable of dissipating the reflected energy without either damaging the fiber or causing it to change position.
- The ideal connection system will employ a method to reduce the Fresnel losses at the surface. This increases the amount of power delivered to the material to be processed, and it also reduces the requirements to dissipate the reflected energy.

The fiber end connection typically consists of a mechanical connector (with mating socket) which rigidly holds the fiber. Possible methods to reduce the Fresnel losses include depositing an anti-reflection (AR) coating on the fiber ends (this technique is routinely used for fixed optics, but until recently has not been feasible for optical fibers).

Output Coupling Optics: The purpose of the output coupling optics is to collect the radiation leaving the fiber, and re-focus it onto the material to be processed. The parameters of the focused beam, which vary with the specific application, include spot size, beam profile, depth of focus, and working distance. The output coupling optics generally includes two separate lens assemblies. The first assembly collimates the beam leaving the fiber. Its f-number[7] must be low enough to collect all of the radiation leaving the fiber[8]. The second lens assembly focuses the collimated beam onto the work piece. The final spot size is a function of the fiber core diameter, the clear aperture of the focusing optics, the working distance of the focusing lens assembly, and any optical aberration.

One of the most important applications of fiber optics is in the field of telecommunications. They have provided the means for efficient and effective inter-continental communication. They also have the significant advantage of being able to handle many thousands of times more calls than an ordinary copper wire. The advent of practicable optical fibers has seen the development of much medical technology. Optical fibers have paved the way for a whole new field of surgery, called laparoscopic surgery (or more commonly, keyhole surgery), which is usually used for operations in the stomach area such as appendectomies. Keyhole surgery usually makes use of two or three bundles of optical fibers. A "bundle" can contain thousands of individual fibers".

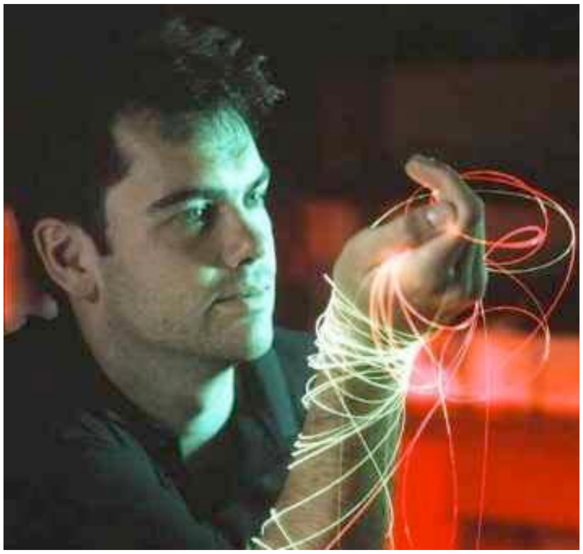


Fig.1.50: *A fiber optic twined on a person’s arm lights up as laser light passes through it*

Optical fibers can be used for the purposes of illumination, often carrying light from outside to rooms in the interiors of large buildings. Another important application of optical fibers is in sensors. If a fiber is stretched or squeezed, heated or cooled or subjected to some other change of environment, there is usually a small but measurable change in its light transmission. Hence, a rather cheap sensor can be mad which can be put in a tank of acid, or near an explosion or in a mine and connected back, perhaps through kilometers of fiber, to a central point where the effects can be measured.

1.5.7 Laser applications in Surface Treatments[1.70]

The idea of using lasers for the modification of surfaces emerged much later than it was brought into the manufacturing industry. The technology still remains in its development stage and its understanding and evaluation is still not completely explored.

It is the strategy of superficial localized heating which is required for best effective surface treatment. Hence, the coherent nature of lasers works to its advantage as it can focus to provide very high power densities. As we study further the applications of lasers into surface treatment we can infer that high powered lasers are much suited for such a process. Here is a graph that can explain it in a more illustrative manner.

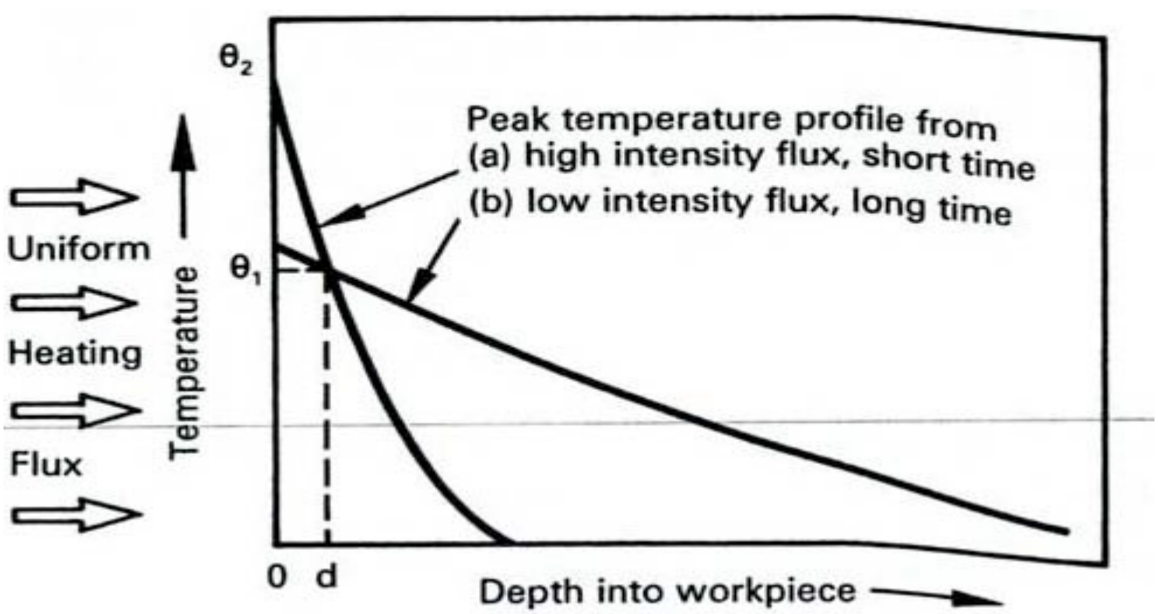


Fig.1.51: *Substrate temperature profiles for high and low heating flux* [1.70]

If the task is to raise a surface layer depth, d, above θ_1 while holding the surface below θ_2 we can deduce that:

- The smaller area under the high intensity flux indicates much less component heating
- Steeper profile of the high intensity flux indicates higher cooling rates

Laser has other traditional competing localized heating sources. Choosing the most optimum process for a specific application requires detailed consideration towards capital costs, geometries, and metallurgy and distortion aspects. It was Breinan who classified the laser treatment regimes in his SME paper based on parameters of parameter density & interaction time. Classified in the order of metallurgical sophistication and process complexity, they are:

- *Martensic transformation hardening*: It is well-known that quenching cast irons and steels from red hot conditions results in hardening. The resulting metastable structure martensite is hard, wear resistant and contains compressive stresses. By proper beam manipulation and controlled laser processing we can produce a hard & wear-resistant cover to an unaffected ductile core. Many investigations are being made in the manufacturing of components such as crankshafts, gears, cylinder liners and other automotive parts. Studies show that alloy and tools are easily treated but structures with widely dispersed graphite or carbide require greater caution. Localized wear patterns on laser treated materials have also been studied.

- *Cladding and Alloying*: These processes involve fusion under conditions where sufficient surface disruption occurs, where trapping and utilization of the beam is necessary.

  Cladding – Laser cladding is defined as the process of providing a fusion bond of coating to a substrate. It has a few advantages over other competing techniques (gas torch hardfacing & electric arc processing) like better metallurgical control, reproducibility, Optimization of coating geometry through controlled power additive and beam distribution.

  Alloying – Traditional laser alloying involves much smaller quantities of additive and greater substrate melting. The high intensity heating flux promotes mixing and creation of the desired components and structures right at the working surface. Most of the work is related to the semiconductor industry. Many other studies have looked into specific alloying operations with carbide-rich coatings, Al-Si alloys etc.

- *Rapidly Quenched structures*: There are many techniques to achieve rapid quenching. Most of them rely on projecting the molten alloy in a vapor form on to a heat sink. We can use laser as a substitute to scan an unheated alloy rapidly with high density flux and produce a sufficiently thin melt layer which then quenches at the substrate surface at the required rate. Studies have been carried on in interesting schemes like ‘layerglazing’ where the objective is to create in bulk material the metallurgical structures in thin layers. With the help of power feed techniques material is fused to a spinning mandrel in a layer which cools very high rates.

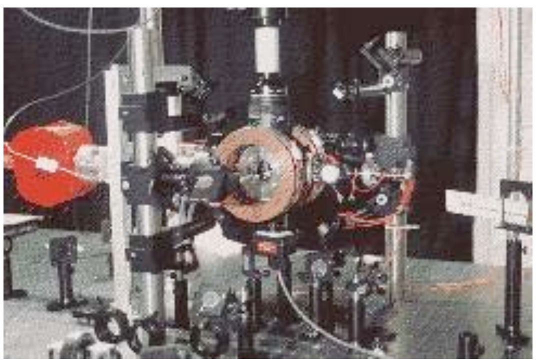
1.5.8 Laser Cooling

The temperature of an object can be related to the average kinetic energy of the particles making up that object, be it solid or gas. On the same lines, the "temperature" of a single atom can be related to its kinetic energy. A higher Kinetic energy results in higher temperatures. Thus, to cool a substance down, we need to slow down the particles.

Light carries a momentum and an energy which are related to its wavelength. When a photon interacts (absorbed or reflected) with a particle, the momentum of the particle must be changed in order to compensate for the change in the photon's momentum (Conservation of momentum). Therefore, the best way to slow down a particle would be to fire a photon at it in the direction opposite to its motion. On interaction with the photon, the particle would slow down. But when the particle relaxes back into the ground state a photon is then emitted having just as much effect to the velocity of the particle. The emission is completely random and hence cancels the effect that it had provided the particle.

When cooling a sample of gas in which particles are moving in random directions with the force of light, we have to ensure that the photons only hit the particles in the direction opposite to motion. The particles only absorb and reemit if the energy of the photons exactly corresponds to a particular energy level transition, or **resonance** of the particles. So if the frequency of the beam of photons is different to a resonance for the particles being cooled, the particles do not "see" the photons and are unaffected. This problem is solved by using an ingenious technique, called **detuning**, which makes use of the effect of the **Doppler shift** for light. The Doppler Effect causes the particles to be affected by different frequencies of light, depending on the speed and direction of their motion. In a gas, the energy of the light, according to a specific particle, depends on its motion within the gas. Whether or not it "sees" a given photon, (i.e. absorbs the photon) will depend upon its speed and direction in the gas. Thus, by choosing a frequency of light just below the frequency for a particular transition in the particle, the absorption will only occur if the particle is moving towards the light. These particles "see" a slightly higher frequency corresponding to the particular transition.

Laser cooling[1.83] uses a set of six lasers, all pointing towards the centre along the axes of a Cartesian coordinate system, i.e. a pair of lasers pointing towards each other on each axis. In this system, each laser gives the particle a "kick" towards the centre, or each pair of lasers reduces that particular component of the particle's velocity to near zero, forming a small blob of very cold particles in the centre. This technique has the ability to cool atoms to temperatures of the order of micro Kelvin. In reality, the particles in the blob are bouncing back and forth between the six lasers at very slow speeds (a few cm/s).



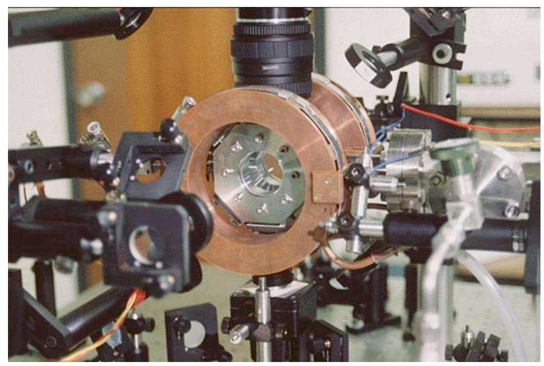


Fig.1.52: *The experimental setup for laser cooling (left) and a close-up of the trapping chamber (right)* [1.83]

As the temperature is reduced, the average velocity of the atoms becomes lower and thus the effect of the Doppler shift changes. Hence, to account for this change in the Doppler shift effect, the frequency of the laser light must be altered correspondingly. This can be done using tunable lasers.

1.5.9. Medical Applications

Laser tehcnology ahs found its applications in varied areas of Medicine. These are:

- Cosmetic surgery – tattoo, scar, stretch mark, sunspot, wrinkle, birthmark and hair removal
- Eye surgery
- Laser scalpel – gynecological, urology, laparoscopic
- Dental procedures
- Imaging
- "No-Touch" removal of tumors, especially of the brain and spinal cord.

The advent of lasers has provided the opportunity for much improvement in many medical techniques. The medical profession has been using lasers in a wide range of applications, from cosmetic surgery to the correction of short-sightedness.

Generally, tissue is a variety of molecules dissolved in water (all of which have electron transitions at particular frequencies, of course). Like electron energy levels, the molecules have particular vibrational energy transitions which they can undergo. If a molecule is struck by light which will not cause an electron transition, the molecule can still absorb the photon's energy through a transition between vibrational energy levels. This causes the molecule to vibrate more rapidly, producing heat. These levels are so close together that the molecule can absorb photons of almost any frequency. However, as some transitions are more likely than others, the fraction of incident photons that are absorbed by the tissue depends on the frequency of the light and the concentration of the specific molecules.

When skin is illuminated with laser light, different effects can be produced, depending on the type of laser used. For example, the 10600 nm infrared light of a CO_2 laser is absorbed by the water in the first few layers of skin cells, rapidly vaporizing them and having little affect on the tissue below. The shorter infrared light (1064 nm) from a Neodymium-YAG laser is absorbed less rapidly, so it penetrates further into the skin. As its energy is absorbed across a greater distance and therefore a larger number of cells, rather than being vaporized, the tissue coagulates. Cells with dark pigmentation can be selectively destroyed using the red light (694 nm) from a ruby laser. Furthermore, while water is transparent to the green and blue light from Krypton (476 nm, 521 nm and 568 nm) and Argon (488nm and 514 nm) lasers, these lights are intensely absorbed by hemoglobin in the bloodstream. This allows access to lesions in the vascular system and in the eye.

- *Cosmetic Surgery:* One of the major fields of medicine in which lasers have taken off is the field of cosmetic surgery. Lasers in this field have wide range of usage from the removal of tattoos to treatment of wrinkles. When laser light is focused to a very small point, high intensities can be generated at these points, because of the light's coherence. To remove tattoos, the high intensity light is used to break up the ink which lies in the skin to make up the tattoo, into fragments. These are small enough to be removed by the body's natural immune systems. Spider veins are veins of small diameter, usually located just below the surface of the skin, that become dilated (larger or swollen). This condition leads to red or purple trace pattern on the sufferer's skin. Spider veins can also cause discomfort, and spontaneous bruising. By tracing the vein with a laser, emitting at a frequency which is absorbed by the red blood cells, it is rapidly heated. This process destroys the vein, leaving the surrounding tissues largely unaffected. As in the case of the tattoo ink, the body's systems break down and remove the vein tissue. For the treatment of wrinkles, short pulses of extremely high intensity light cause the coagulation of small regions of tissue. The energy of these pulses is absorbed quickly by the target area, so that the heat transfer to the surrounding tissue is minimal. When positioned correctly, these pulses can remove much of the visible effects of wrinkles.

- *General Surgery:* Lasers can, naturally, also be applied to general surgery. By choosing a wavelength which causes rapid and controlled tissue vaporization, we have in effect a `light scalpel'. This laser knife, while cutting the patient's flesh, seals blood vessels and nerve endings, often greatly reducing bleeding and pain during and after the operation. This process is called ***cauterization***. Furthermore, as lasers can be easily directed using an optical fiber system, it lends itself to use in laparoscopic or keyhole procedures. This is where a number of small incisions are made in the patient, and all operative work is carried out through these holes. This drastically reduces the recovery time and discomfort for the patient as well as the risk of complications. Additionally, this greatly reduces the scarring after the operation. Surgeons have also applied lasers to the treatment of sufferers of severe inoperable angina, which is low blood flow to the muscles that make up the heart itself. Using a powerful laser to burn millimeter width holes in the wall of the heart, the surgeons can create a number of small channels through the muscle. The holes in the surface of the heart are quickly closed by clotting Blood can flow through these channels, bringing an increase in oxygen to the heart muscles and thus relieving the angina.

- *Ophthalmology:* Ophthalmologists have also capitalized on the discovery of lasers and their uses in surgery, developing a number of techniques using lasers to correct myopia and hyperemia (near and long sightedness). Most prominent are the processes known as ***PRK*** (Photorefractive Keratectomy) or ***LASIK*** (Laser In-Situ Keratomileusis). These methods use a laser to alter the shape of the cornea in the patient's eye, removing much of the risk for human error associated with the more traditional method of radial keratotomy, where a surgeon uses a scalpel. In PRK the laser directly burns away at the surface of the cornea.

Fig. 1.53: *In PRK Surgery, the laser beam acts directly onto the corneal membrane*[1.86]

Alternatively, the LASIK procedure involves cutting a flap in the surface membrane of the cornea with a very precise scalpel, leaving a small `hinge' of tissue as a connection, and altering the shape of the cornea beneath, before replacing the flap. The LASIK method allows for recovery of vision almost the same day and greatly reduces post-operative pain.

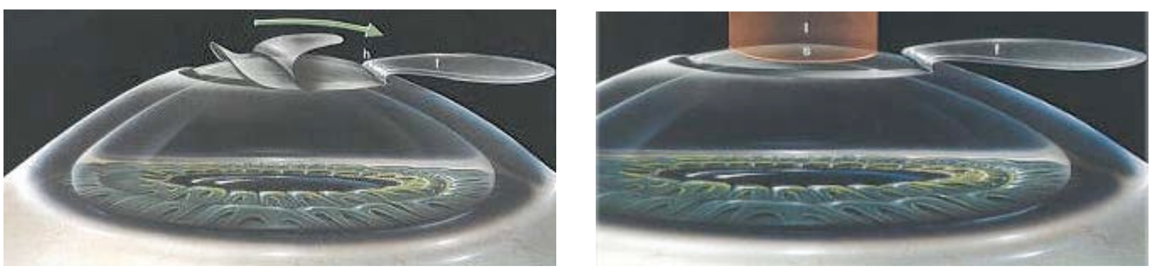


Fig. 1.54: *In LASIK Surgery, a flap of the corneal membrane is peeled back (left). The laser acts on the lower layer of the membrane and the flap is replaced (right)* [1.86]

By altering the shape of the cornea the opthamologists are able to provide corrections for the defects in the lenses of the patient, instead of using glasses or contact lenses. Many of the patients realize such great improvement in vision that they no longer require glasses for driving. This is but a sample of the uses developed for lasers in surgery and other areas of the medical profession. New applications of lasers in medicine are being constantly discovered to increase the safety and quality of the lives of patients.

CHAPTER 1.6
FUTURE OUTLOOK

With the rapid advancement in laser technology, several fields are looking forward to adopt its viable applications and incorporate them instead of conventional techniques. With strict attention given to the application of lasers in drilling for the Oil and Gas industry, the GTI has provided a vast amount of convincing results regarding the subject. As high power lasers have proven to be successful in penetrating rocks, the daunting task of delivering the laser power to the rocks at the downhole situation still remains.

1.6.1 Downhole laser application

Lately fiber lasers have increased in power capacity from several watts to kilowatts. Over the past few years, advancements in fiber optics have shown that substantial amount of high powered laser energy can be transported via fiber optics. They have rapidly evolved into a prospective method for on-site applications including hard rock mining, tunneling, pavement cutting and rock drilling. Research development boasts of cultivating a energy delivery system for downhole applications. Such a system as suggested by the GTI is presumed to consist of an identifying portable laser source, optical fiber beam delivery system and a downhole applications tool. With the present norms and limitations, the laser technology can be used for regulating formation damage and stimulating oil and gas production. Moreover laser power could be used as a drilling device solely for the purpose of getting through hard rocks that pose a threat to the durability of the drill bits.

With the selective laser properties as used in laser cleaning (discussed in section 1.5.3), operators can manipulate the laser parameters such as wavelength , power , beam size, pulse frequency etc. to aim at particular formation damages. With the degrees of freedom of one parameter with respect to the other lasers can be exploited for jobs specific to the downhole conditions.

The GTI has currently proposed to employ laser as a means to remove rock areas that have been damaged at the wellbore. With the controllable laser beam size and ease of handling, the operator can precisely chip away the damaged parts of the rock. This method is quick, requires lower costs, avoids mechanical parts downhole of the purpose and may prove highly efficient than the other conventional methods.

Another significant laser application tested and suggested by the GTI is perforating production casings at the wellbore location instead of using shaped charges. Recently, a 1.0 cm thick steel tubing and Berea sandstone were cemented together. A 4 kW diode Nd:YAG laser was demonstrated to produce easy penetrations through the clad structure in about 8-10seconds using a purging gas of compressed air. Laser perforations have a lot of advantages over shaped charges. Their use as an alternative method to conventional explosive charges could reduce and in later cases even eliminate perforation damage and significantly boost production rates and overall economic return.

As GTI develops a method to chip away damaged parts of the reservoir at the downhole, this method could be used right after the perforation process to clear out any perforation damage caused. This eliminates the whole tripping process required to remove any damage caused by the perforation process.

1.6.2 Geological Investigation of Lunar and Martian Subsurface Using Laser Drilling System

Gahan, B. and Batarseh, S., Reilly, James F., Wilcox, Brian H.

2004, Space 2004 Conference and Exhibit

Laser energy has been found to be successful as employed for drilling rocks. Once a prototype for on-site rock drilling is fabricated scientists look forward to use such a model for excavating Martian soil[1.87]. After establishing a human presence on the moon, NASA has recently ventured into Martian lands announcing robotic exploration programs for probing planetary surfaces. The first and foremost objective is the geological investigation of the surface and the deeper crust. These investigations may include acquisition of samples for analysis, surface mappings and geochemical investigations of the soils and outcrops. As water is the most essential condition for human habitation, search for water is the most critical part of the investigation. Although liquid water on Mars will quickly evaporate, photographs transmitted back to Earth by previous NASA missions to the planet reveal giant flood channels, dry river beds, and flood plains on the surface. This evidence of past water on Mars leads some scientists to consider Mars as the prime location in the Solar System to search for extraterrestrial life. To be able to quantitatively arrive at Mars' water budget both direct and indirect methods of investigations are required. There Exploration robots and systems should be light and flexible, both to reduce transportation costs to Mars and mobility on the surface. It should also be robust to the adverse. For a drilling system to satisfy these prerequisites, laser drilling systems provide an attractive option for future planetary exploration. The GTI investigations on laser rock interactions have prompted scientists to experiment with rocks similar to the ones found on the Martian surface.

Positive results have been obtained on most experiments as low SE was required for Volcanic Tuff and Hematite. The challenge still remains at the field application, primarily in remote location like Mars.

Another mechanism that was investigated by Jurewicz is based on the concept that a laser used in drilling application produced thermal degradation and cracking around the circumference of the hole. Jurewicz utilized the weakened laser drilled hole for blasting and disintegrating rock. He then combined the two methods into a laser-impactor excavation system that could drill 10-30-cm holes into the rock face and the impactors/explosives then inducer failure/breakage in the rock. The process envisaged by Jurewicz is illustrated on Figure 1.27.

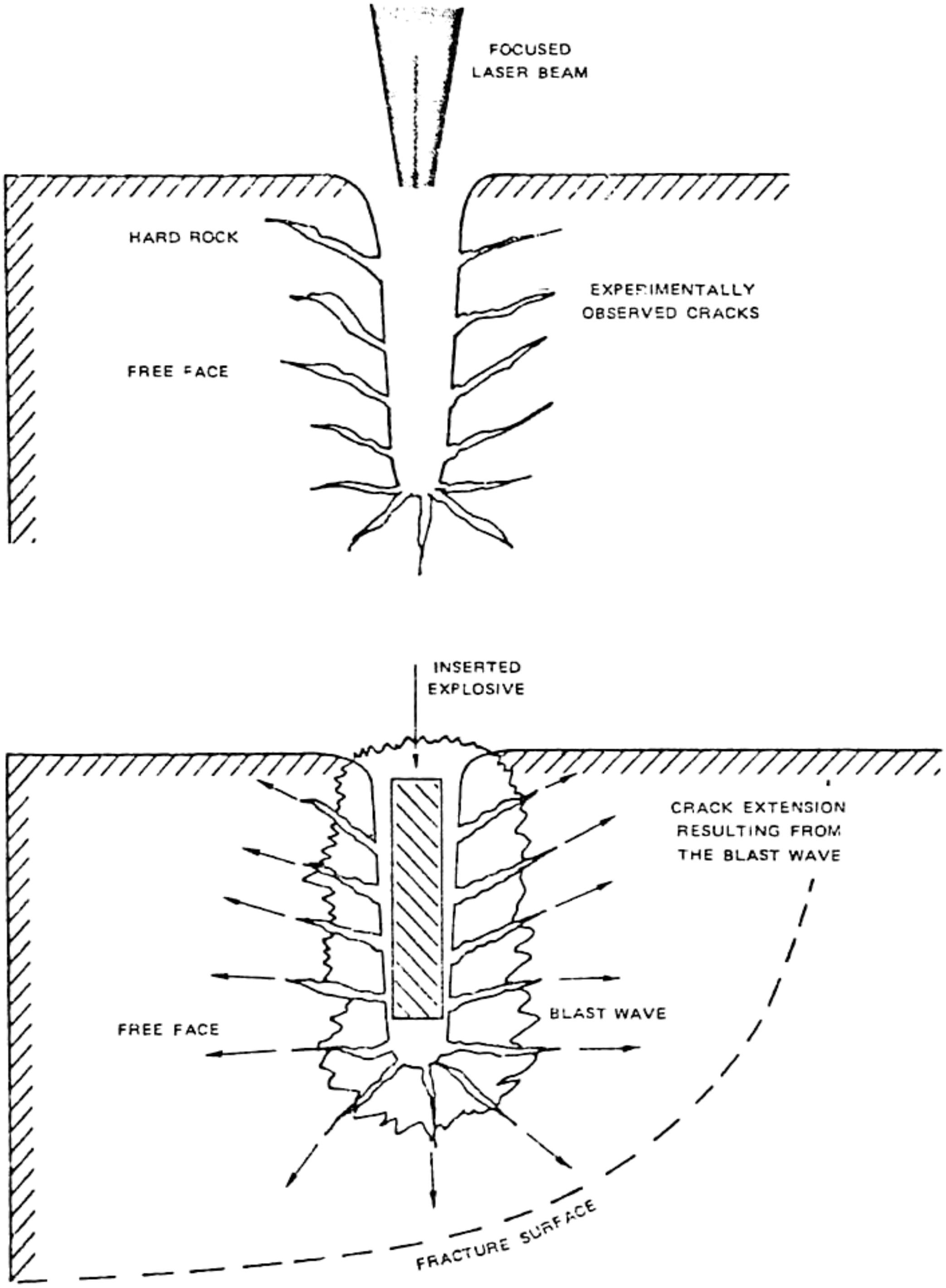


Figure 1.27: *Laser drill and blast technique*

Venghiattis [1.40] patented a laser well perforating drill. He utilized a ruby laser to burn holes or slots through the steel casing and into the oil-gas bearing formation. The laser is rotated downhole by an electric motor at the specified depth. With the vertical displacement control of the motor, it is possible to create any configuration of perforations. Van Dyk[1.39] and Stout[1.38] independently developed techniques that utilized lasers for stimulating oil-bearing zones and improving the recovering of hydrocarbons. The concept is interesting; bit it appears to be impractical. Figure 1.28 illustrates the process.

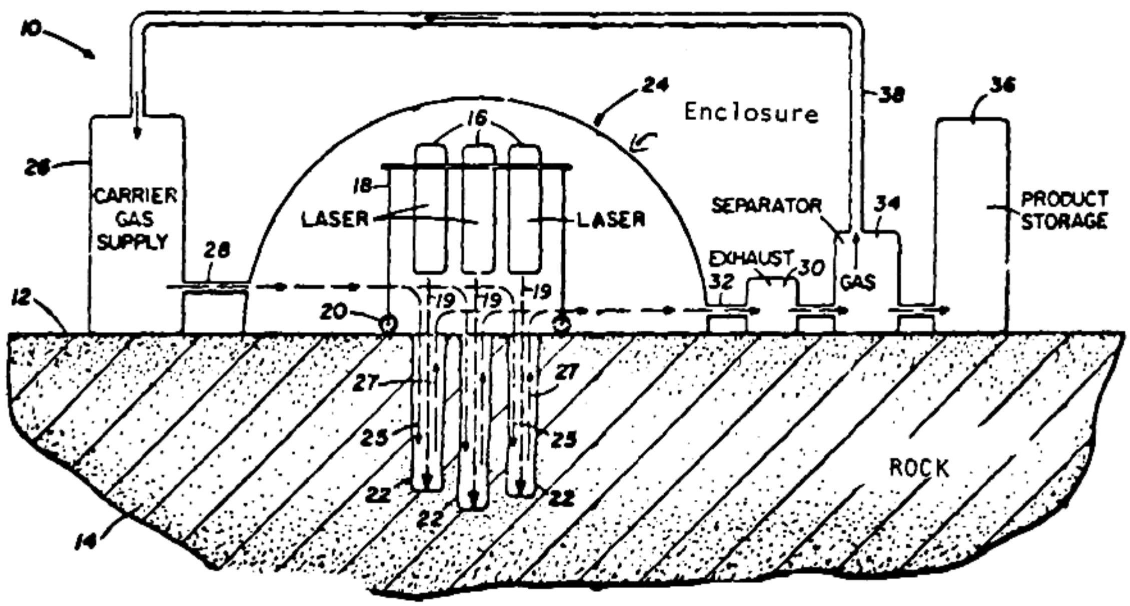


Fig.1.28: *Mineral Recovery system using lasers (Van Dyk, 1970)* [1.39]

Modern concepts

For tests conducted with the **Nd:YAG Laser** with sandstone, the amount of material removed decreased with each successive burst. Increasing the relaxation time might improve the results; but further tests are required to verify this hypothesis. Tests conducted with two and three-spots reveal that no additional weight loss is realized as the number of bursts per shot increases. The difference in SE was referred to the obvious relaxation time difference due to difference in spot pattern. Three and four spot tests demonstrated very little melting even though they were tested for 10-15 repeats on each spot.

In tests conducted with Shale, cutting was more easily achieved than in the other lithologies; but SE values were reported to be teststhe rock cut more easily than it did for the other two lithologies but SE values were reported relatively higher. SE behavior was found to be similar to the case of sandstone. SE also increased with increasing number of bursts.

CO_2 Laser

The CO_2 laser had a higher average power allowing higher power densities.

Sandstone: Results were found to be similar to those when conducted by the Nd:YAG laser. Therefore high power densities do not affect the pattern of results.

Limestone: The higher average power available from this laser allowed the hole size to be expanded to the wanted 1.27 cm. SE values obtained were found to be much lower than tests from the Nd:YAG laser, often by an order of magnitude.

At the end of this stage of the project the team published a paper for SPE, 2003 and the 22nd ICALEO, 2003 relating to these outcomes. The results produced in these papers did not convey the completeness of the fundamental work required to achieve the final aim of designing a field prototype. The results help us perceive what the drilling system could appear like.

Other important concepts that draw attention were attended in the following studies.

Laser Drilling: Effects of Beam Application Methods on Improving Rock Removal[1.60]

Richard A. Parker; Brian C. Gahan; Ramona M. Graves; Samih Batarseh; Zhiyue Xu and Claude B. Reed
2003, SPE 84353

Drilling Large Diameter Holes in Rocks Using Multiple Laser Beams[1.61]

Richard Parker; Zhiyue Xu and Claude Reed; Ramona Graves; Brian Gahan and Samih Batarseh
2003. 22nd ICALEO

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APPENDIX B

M I C R O W A V E S

ABSTRACT

New developments and innovative ideas in the area of materials processing have often led to the discovery of new materials, with interesting and useful properties, and/or new technologies which are *faster and better* (improvement in product performance), *cheaper* (energy-efficient and cost-effective), and *greener* (environmentally friendly). A striking example is the recent innovations and interesting developments in the area of microwave processing of ceramics. A field which had made little progress for a decade was shown to be at the stage as demonstrated by the presentations at the First World Congress on Microwave Processing held in Orlando, Florida, Jan. 5, 1997. Among the most prominent advances were those reported on tungsten carbide (WC) based cutters (universally used in drill bits). This has opened up new avenues and opportunities to utilize this new process in developing an entirely new and revolutionary family of drill bits for geothermal, oil, gas, mining, excavation, and other industries.

Various current drilling systems (both conventional and advanced) used in oil, gas, geothermal, minerals, tunneling, mining industries, require improvements in bit technology to not only improve the performance of these systems, but also to reduce the overall cost of drilling. It is believed that due to the size of the industry even small savings in the overall cost of drilling would translate into large dollar amounts. Microwave heating is fundamentally different from conventional heating. In the microwave process, the heat is generated internally within the material instead of originating from external sources. It is a specific function of the material being processed, and there is almost 100% conversion of electromagnetic energy into heat largely within the sample itself unlike in conventional heating where there is considerable wastage of thermal energy. Due to the volumetric and internal heating, the thermal gradients and the flow of heat in microwave-processed materials are the reverse of those in conventional heating. Due to highly efficient energy transfer and rapid heating rates, the material can

be processed in a few minutes. Consequently, microwave field make it possible to heat both small and large shapes very rapidly, uniformly, and efficiently. This in turn is critically important in case of tungsten carbide-cobalt (WC/Co) based products where undesired grain growth can be prevented by rapid heating and short sintering periods.

Hard metal ceramic composites due to their unique combination of hardness, toughness and strength, especially the tungsten carbide (WC) based composites, are universally used in cutting tools and drills, machining of wear resistant metals, mining, and geothermal drilling. Conventional methods for sintering tungsten carbide with cobalt as binder involve high temperature and lengthy processing cycles (about 24 hours), and make the production cost of these materials quite high. Furthermore, these conventional conditions during processing favor the WC grain growth in the presence of Co melts. Consequently, the mechanical strength and hardness of the tool is diminished. This manual discusses microwaves and provides necessary information for using them in various applications.

LIST OF FIGURES

CHAPTER 2.1
INTRODUCTION

The term microwave is used to denote that part of the electromagnetic spectrum for which the free space wavelength is less than approximately 0.5 m, extending into the region of millimetric wavelengths. In terms of frequency the coverage is about 0.5 GHz - 100 GHz, and over. One characteristic of microwaves is that the wavelength is, at most, of the order of (and often much less than) the dimensions of the circuits ordinarily used at lower frequencies. This is a factor that will clearly influence circuit design. Another characteristic is that it becomes possible to consider radiation at such wave lengths in terms of quasi-optical behavior. The analogy is useful, structures of many wavelengths in dimension become possible, although it must not be forgotten that a wavelength of 0.1 m is some 10^5 wavelengths of visible light. It is the ability to form well defined beams of radiation that has made the use of such frequencies attractive for a range of purposes. These frequencies when coupled with the wide band widths are used as communication channels for modulation of high frequency carriers.

For convenience various regions of the microwave spectrum have been given internationally recognized alphabetical designation. Although diverse applications of microwaves exist they have certain aspects in common, there will usually, although not always, be a transmitter at a suitable power level feeding a transmitting antenna, the radiated waves will traverse a medium before falling on a receiving antenna; and finally the low level signal received will require amplification and processing for display. The 'receive only' part of the system would be relevant to the measurement of radiation coming from natural sources as in radio astronomy. These three aspects- power sources, propagation and reception – will be briefly considered further.

2.1.1 Power sources

Generally, conventional oscillators of the type used at lower frequencies can be used in the microwave spectrum provided suitable transistors and circuit configuration are used.

Bipolar silicon transistors are usable up to approximately 4 GHz; gallium arsenide field effect transistors up to approximately 10 GHz. (These limits are continually being extended by improvements in materials and manufacturing techniques.)

Transistors such as these are a comparatively recent development. Conventional devices, such as vacuum triodes, would not work at these high frequencies. Consequently a number of devices using different methods of electron-wave interaction were developed. These included the klystron, magnetron and traveling wave tube. These devices still have their place in microwave systems, performing tasks not possible with solid-state devices. In particular the need for high power can only be met using these devices (the peak powers required in radar systems for example are of the order of megawatts). Despite the potential failure problems in thermonic vacuum devices, many of the power amplifiers flown in satellites use traveling wave tubes. It is important to realize that as the frequency increases it becomes more difficult to generate a given power.

2.1.2 Propagation

Propagation of microwaves is understood better in their transmission over long distances. Hence, radar propagation is discussed in detail. Power from the transmitter is fed to an antenna, which is designed to have directional properties appropriate to the application. The distances involved in connecting the transmitter and its antennas (and also receiver to its antenna) are likely to be many wavelengths, so transmission lines or waveguides must be used. This applies to most interconnections between and within circuits, so an understanding of wave propagation on transmission lines and waveguides is necessary.

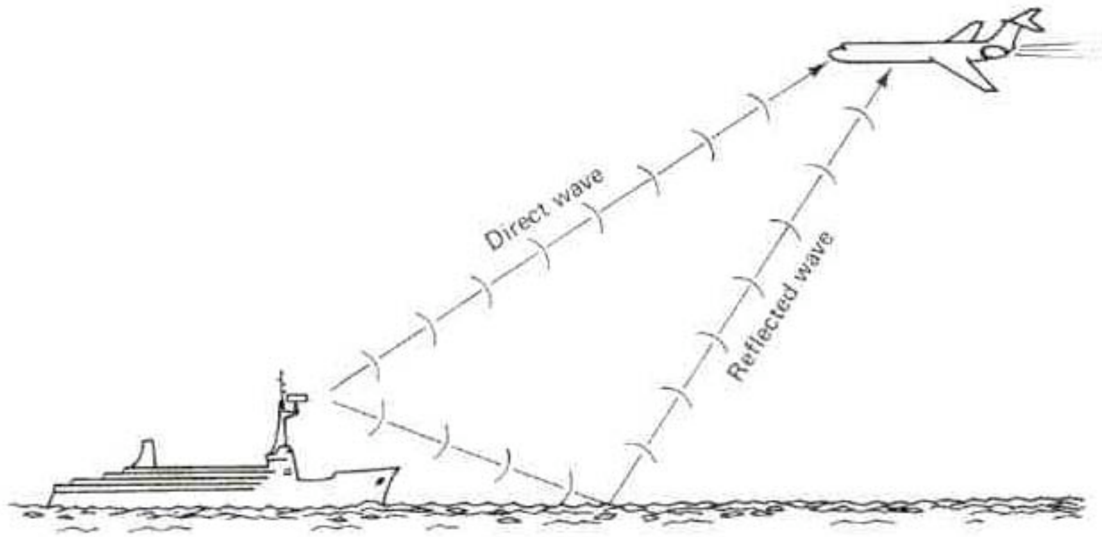

Fig. 2.1: *Direct and Reflected waves*

Wave propagation occurs either directly or by reflection from other objects. This can be demonstrated on the Figure 2.1 above. In most microwave installations direct waves are used but in some cases reflected waves play a very important role. The half-wave dipole used as a primary radiator at lower frequencies becomes of limited use as its size decreases. Most antennas will use a reflector irradiated from a primary feed antenna. Although a dipole might be used for this purpose, waveguide feeds are usually more suitable. Apart from the power levels involved, the receiving antenna may be identical, and indeed the same antenna may be used for both transmission and reception.

The medium in which propagation between antennas most often takes place is the atmosphere. To a first approximation this may be considered as free space, and the characteristics of an antenna radiating into free space will apply. In detail however the small but finite refractive index of the atmosphere has an effect. For 'point to point' transmission the ray bending caused is of the same order of magnitude as the apparent ray bending resulting form the finite radius of the earth. In addition to ray bending, which does not depend greatly on frequency, attenuation due to atmospheric gases becomes important above 10 GHz. Precipitation in the form of rain or snow can cause severe attenuation.

2.1.3 Reception

The energy incident on the receiving antenna will be fed via a transmission line or waveguide to a receiver. Sometimes the effects of losses in the connecting line are avoided by mounting part of the receiver very close to, or on the antenna. This part is then referred to as a head amplifier. The receiver itself must amplify the received signal and extract the modulation carrying the information. At lower radio frequencies, receivers are usually of the super-heterodyne type, in which the modulation on the carrier is transferred to a lower place by mixing the signal with a local oscillator in a non-linear device, the mixer or frequency changer, from which is extracted the difference frequency. The non linear device at microwave frequencies is a semiconductor diode, formerly a crystal of silicon with a tungsten cat's whisker, now more commonly a schottky barrier diode. The local oscillator is required to produce perhaps 10 mW at a frequency differing from the carrier by the intermediate frequency, often 70 MHz. The gain-frequency characteristic of the reservoir is then determined by suitable (Intermediate frequency) IF filters. Finally the modulation is extracted from the intermediate frequency signal in a detector, or demodulator. Depending on the performance required and complexity warranted, some amplification of the carrier frequency may be included. In other cases the signal from the antenna is taken directly to the mixer.

2.1.4 Noise

Even at this early state in the discussion of the transmission of the microwaves it is desirable to introduce the concept of noise. An antenna at any frequency connected to a sensitive receiver will show background more. Some will arise from natural sources, such as the sun (where it forms the low frequency partion of a spectrum peaking in the visible frequencies) or interstellar gas clouds; some will be man made, such as is caused by sparking attendant to ignition systems. With any electrical signal there will be associated electrical noise, and it is the ratio of signal to noise, which determines the accuracy with which information in the signal can be extracted. Noise initially present with a signal will be increased by noise sources inherent in amplifiers, so that the quality and utility of an amplifier must be judged by its effect on the signal-to-noise ratio as well as by gain. To give an order of magnitude to noise signals, it is convenient to quote the formula for the noise power delivered by a resistor into an equal reservoir:

$$P = k\,T\,B \qquad \text{------ (Eq 2.1.1)}$$

Where, T is the resistor temperature (degrees Kelvin), B is the bandwidth of the measuring circuit (Hz) and k is Boltzmann’s constant, 1.30 E-23 J K^{-1}. P is given in watts. Thus, a resistor at room temperature (290^{o} K) delivers 4 E -15 W into a bandwidth of 1 MHz. This may seem small; but, calculation will verify that for a 50 Ω resistor, the corresponding (root mean squared) rms open circuit voltage is about 1μV, which is not so insignificant.

CHAPTER 2.2
HISTORY

Historically, microwave technology goes back to the experimental work of German Heinrich Hertz that was conducted during 1879 through 1886. Using a spark gap generator and parabolic reflector, Hertz generated electromagnetic waves at frequencies as high as 450 MHz. He conducted experiments that proved Maxwell's theories were correct. Hertz began testing these theories by using a high-voltage spark discharge (a source rich in high-frequency harmonics) to excite a half-wave dipole antenna. A receive antenna (antenna positioned at the receiving end of the transmission, the other end is known as transmit antenna) consisted of an adjustable loop of wire with another spark gap. When both transmit and receive antennas were adjusted for the same resonant frequency, Hertz was able to demonstrate propagation of electromagnetic waves.

In another experiment, Hertz used a coaxial line to show that electromagnetic waves propagated with a finite velocity. He discovered basic transmission line effects such as the existence of nodes in a standing wave pattern a quarter wavelength from an open circuit and a half wavelength from a short circuit. He then went on to develop cylindrical parabolic reflectors for directional antennas, as well as a number of other radio frequency (RF) and microwave devices and techniques. Guglielmo Marconi's early experiments in radio communications, from 1894 to 1896, were at frequencies as high as 1 GHz. Interest shifted away from microwave frequencies for use in radios, when it was found that much longer distances of transmissions were possible at lower frequencies. Over the next three decades, most of the important developments in radio communications were at lower frequencies- wavelengths from about 200 to 10,000 meters.

One significant development in the microwave area [2.59] was the invention of the Barkhausen Kurz tube in 1919, which made it possible to build effective oscillators at frequencies above 300 MHz. During the 1930's, there were a number of other important developments in microwaves. Marconi experimented with line-of-sight communication links at frequencies around 600 MHz. In 1933 he installed a microwave link between the

Vatican and the summer residence of the Pope, a distance of 15 miles. In 1931, A.G. Clavier directed the setting up and demonstration of a microwave link between Dover, England and Calais, France. Also significant during this period, was the work of George C. Southworth and W. L. Barrow in developing hollow waveguides.

It was the need for radar during the World war Π that stimulated a very rapid growth in microwave technology. The invention and improvement of microwave sources and amplifiers have been milestones in the history of microwaves. The Barkhausen tube has already been mentioned. Another important advance was the invention of the klystron tube in 1939 by R. H. and S. F. Varian. The development of the high power cavity magnetron by J. T. Randal and H. A. H. Boot in 1940 made effective radar systems possible. The invention of the traveling-wave tube amplifier by R. Kompfner in 1944 greatly enhanced the application of microwaves for communications. In more recent years, many advances have been made in developing solid-state devices as sources and amplifiers at microwave frequencies. One of the first important devices of this type, the Gunn diode, is based on a phenomenon observed by J. B. Gunn in 1960. Integrated circuit techniques have been extended to the fabrication of microwave circuits. This has made it possible to greatly reduce the size of the microwave circuits so that complete microwave systems and subsystems can be put on a single semiconductor chip.

Electromagnetism, Maxwell's Equations, and Microwaves

Although scientists knew a good deal about both electricity and magnetism by 1750, no one yet suspected that there was any connection between the two. We now know that both the electric force that attracts bits of paper to a comb and the magnetic force that attracts a steel paperclip to a magnet are different aspects of the same force, the "electromagnetic" force. Electricity and magnetism are intimately related in a complex way [59]. Discovery of this relationship, eventually led to the discovery of radio waves and microwaves.

In 1820, the Danish physicist Hans Christian Øersted found that if he moved a wire carrying an electric current near a magnetic compass needle, the needle tended to turn at right angles to the wire. This was the first direct evidence that electricity and magnetism were related. In the following four decades, other physicists such as Michael Faraday and Joseph Henry studied this relationship in more detail. Many of them tried to develop a theory to explain exactly how electricity and magnetism were related, but they encountered great mathematical and experimental problems.

The man who overcame these problems and developed a comprehensive theory of electromagnetism was Scottish physicist James Clerk Maxwell. During the 1860’s, he devoted several years to the problem of electromagnetism, and published his results in their complete form in 1873. At the time few physicists could understand Maxwell’s work, but in the following years the world recognized that Maxwell had written down the essential laws of electrodynamics, which is how the electromagnetic force operates. Today Maxwell’s discovery can be expressed in four short equations called Maxwell’s Equations.

These equations allowed for the existence of invisible electromagnetic waves with much longer wavelengths than light. In a series of experiments beginning in 1886, the German physicist Heinrich Hertz proved that these long electromagnetic waves were real. He showed this when he generated what are referred to as radio waves with an electric spark. These “radio waves” were transmitted along the length of his laboratory, and produced a smaller spark at his receiver. By showing that these “Hertzian waves” traveled in beams and could be focused like light rays, Hertz convinced the scientists of his time that he had discovered the long electromagnetic waves that Maxwell’s equations had predicted. In the 1890’s, other physicists repeated and expanded Hertz’s experiments. The Indian physicist Jagadish Chunder Bose, for example, produced and experimented with waves as short as 5 millimeters (less than a quarter of an inch, but with a wave-length much longer than that of light).

CHAPTER 2.3
PHYSICS

Generally, microwaves are viewed as something used to heat a dinner or make popcorn. A typical microwave oven needs several hundred watts of energy to generate microwave energy powerful to have application in an oven. This chapter discusses some of the basic characteristics of microwave and its properties. An understanding of these basic characteristics is necessary when considering different applications.

Like light, microwaves travel very fast, about 186,000 miles (300,000 kilometers) per second in air. No electromagnetic wave, or anything else for that matter, can travel faster. In addition, both light and microwaves get weaker the further they travel from their source, and both can be focused into narrow beams by lenses (such as a magnifying lens) or concave mirrors called reflectors. In devices such as flashlights and car headlights, light is focused by specially shaped mirrors. Similarly, microwaves can be focused in dish-shaped reflectors.

Though similar in many respects, microwaves and light have one major difference—one can see light or its reflection on objects. Microwaves, by contrast are not visible. This is because of the difference between the wavelengths of microwave and light waves.

Light waves and microwaves are both electromagnetic waves and, therefore, part of the electromagnetic spectrum. The electromagnetic spectrum is the range of all electromagnetic waves. It includes everything from radio waves to microwaves, infrared and ultraviolet rays, and gamma rays.

Electromagnetic Spectrum:
Radio waves | *Microwave* | Infrared | Visible light | Ultraviolet | X-ray | Gamma ray

Each of the different types of waves has a different wavelength. The length of a wave is the distance from one peak of a wave to the next peak. Microwaves are electromagnetic waves. Their wavelength of 1-centimeter to 30-centimeter (about half an inch to a foot) makes them longer than infrared light, but shorter than radio waves. Figure 2.2 indicates the microwave region of the electromagnetic spectrum. The boundaries between infrared light and microwaves, and microwaves and ultra-high-frequency radio waves are fairly arbitrary and are used variously among different fields of study.

In the case of microwave ovens, the commonly used electromagnetic wave frequency is roughly 2,500 megahertz (2.5 gigahertz). Microwaves in this frequency range have an interesting property: they are absorbed by water, fats and sugars. When they are absorbed they are converted directly into atomic motion - heat. Microwaves in this frequency range have another interesting property: they are not absorbed by most plastics, glass or ceramics. Metal reflects microwaves, which is why metal pans do not work well in a microwave oven.

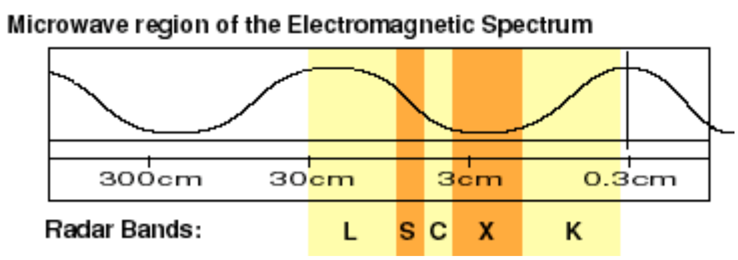

Fig. 2.2: *Source: http://imagers.gsfc.nasa.gov/ems/micro.html*

As indicated, microwaves have wavelengths that can be measured in centimeters. The longer microwaves, those closer to a foot in length, are used to heat food in a microwave oven. Microwaves also have use for transmitting information from one place to another because microwave energy can penetrate haze, light rain and snow, clouds, and smoke. Additionally, shorter microwaves are used in remote sensing. Applications such as the Doppler radar used in weather forecasts. Microwaves, can also be used to transmit information like telephone calls and computer data from one city to another.

As previously indicated Maxwell's equations predicted the existence of microwaves. The physical concepts, however, and their applications demonstrate the usefulness of this technology. Microwaves theory and techniques of today permit circuits to be modeled on the computer in great detail. The circuit can be built up ‘on paper’ and exercised to ascertain its performance over wide frequency bands, temperature ranges and variations in dielectric constants, mechanical dimensions and components. The computer can account for nuisance problems like irregularities due to discontinuities, propagation velocities that may vary with frequency and small attenuations that accumulate to have a large effect on overall design. Once the model on the computer is made to perform satisfactorily, a working model can be fabricated and tested. Measurement with respect to its performance can be carried out automatically with great precision using a computer controlled network analyzer. If any difference exists between the experimental model and the computer model, it can be reconciled by experimenting on the computer model. When the troublesome design parameter is isolated, a working model is modified and the modifications are noted for future designs. Before computers and computer programs were available, the design cycle was much slower and more empirical. The mathematical concepts used today did not exist in the 1950’s. It was not possible to combine discrete components and transmission lines in the same formulation. Mathematical manipulations of these two types of matrices provide the capability necessary for design problems.

The future chapters will discuss the microwave applications, with an emphasis on those pertaining to oil and gas in detail.

2.3.1 Microwave Units

Microwave engineering progressed rapidly during World War Π. Because the early documentation used a mixture of English, CGS and MKS units, this convention has continued on into today's literature and practice. For example the inside dimensions of a common-sized waveguide are 0.4 by 0.9 inches, whereas two common 50-ohm coaxial air lines measure 3.5 mm and 7 mm as the inside dimension of the outer conductor respectively.

Decibel

The decibel parameter describes the ratio of two quantities. Typically, these are the output and input power of an amplifier, called the power gain of the amplifier. Mathematically:

$$\text{Power gain} = \frac{P_{out}}{P_{in}} \qquad \text{-------- (Eq 2.3.1)}$$

Decibels:

$$\text{Gain} = 10\log_{10}\left(\frac{P_{out}}{P_{in}}\right)dB \qquad \text{-------- (Eq 2.3.2)}$$

The power gain in decibels is equal to 10 times the base 10 logarithm of the power gain (power ratio). The decibel is one-tenth of a bel, a unit named after Alexander Graham Bell. It is the unit of change in audio level that is discernable by the ear.

2.3.2 Bandwidth

Bandwidth is a measure of the amount of the spectrum to which a microwave system can respond. Bandwidth is often given in Megahertz or Gigahertz, calculated from a lower frequency FL to an upper frequency FH, the bandwidth is given by (FU-FL). Bandwidth is expressed in a number of other ways:

- Three-dB bandwidth: for a network that has a non-ideal frequency response, the three-dB bandwidth is where the transmission coefficient S21 falls off from its highest peak by three dB. Similarly, the two-dB and one-dB band networks are where the transmission coefficient S21 falls off from its highest peak by two-dB and one-dB respectively.

- Percentage bandwidth: for a system that works from a lower frequency FL to an upper frequency FH, the percentage bandwidth is given by 100%x (FU-FL)/FC. FC is the center frequency, equal to (FU-FL)/2. Note that it is possible to have more than 100% bandwidth by this definition; an amplifier that works from 100 MHz to 10 GHz has a bandwidth of 200%.

- Instantaneous bandwidth: a measure of the width of a spectrum to which a system can respond, without any tuning. Using the analogy of radio, the IF bandwidth in an American FM receiver is about 200 kHz. This bandwidth is necessary to pass the full spectrum of a broadcast FM signals. The demodulator processes this bandwidth to obtain a base band that is approximately 18 kHz in width. The "despreading" effect of this processing results in the superior signal to noise ratio realized by FM transmission.

- Tunable bandwidth: a measure of the width of a spectrum to which a system can respond with changes in settings such as the local oscillator frequency. For a receiver, the tunable bandwidth is almost always more than the instantaneous bandwidth. An AM radio has a tunable bandwidth of 540 kHz to 1600 kHz, or over one MHz of bandwidth. This is about 100X its instantaneous bandwidth.

- Octave bandwidth: it implies that the upper frequency of operation is double the lower frequency of operation. For example, an amplifier that works from 2 to 4 GHz has one octave bandwidth.

Waveguide Frequency Bands			
Frequency Band	Waveguide Standard	Frequency Limits (GHz)	Inside Dimensions (inches)
R band	WR-430	1.70 to 2.60	4.300 x 2.150
D band	WR-340	2.20 to 3.30	3.400 x 1.700
S band	WR-284	2.60 to 3.95	2.840 x 1.420
E band	WR-229	3.30 to 4.90	2.290 x 1.150
G band	WR-187	3.95 to 5.85	1.870 x 0.940
F band	WR-159	4.90 to 7.05	1.590 x 0.800
C band	WR-137	5.85 to 8.20	1.370 x 0.690
H band	WR-112	7.05 to 10.00	1.120 x 0.560
X band	WR-90	8.2 to 12.4	0.900 x 0.450
Ku band	WR-62	12.4 to 18.0	0.622 x 0.311
K band	WR-42	18.0 to 26.5	0.420 x 0.170
Ka band	WR-28	26.5 to 40.0	0.280 x 0.140
Q band	WR-22	33 to 50	0.224 x 0.112
U band	WR-19	40 to 60	0.188 x 0.094

V band	WR-15	50 to 75	0.148 x 0.074
E band	WR-12	60 to 90	0.122 x 0.061
W band	WR-10	75 to 110	0.100 x 0.050
F band	WR-8	90 to 140	0.080 x 0.040
D band	WR-6	110 to 170	0.0650 x 0.0325
G band	WR-5	140 to 220	0.0510 x 0.0255
	WR-4	170 to 260	0.0430 x 0.0215
	WR-3	220 to 325	0.0340 x 0.0170
Y-band	WR-2	325 to 500	0.0200 x 0.0100
	WR-1.5	500 to 750	0.0150 x 0.0075
	WR-1	750 to 1100	0.0100 x 0.0050

Figure 2.3: Waveguide Frequency Bands

2.3.3 Transmission lines and characteristic impedance

A transmission line is any conducting structure that supports an electromagnetic wave "in captivity". Most transmission lines use two conductors, where one is considered to be the ground. This includes coaxial cable (the outer conductor is ground), microstrip and stripline. The transmission line that does not use a pair of conductors is a waveguide. The substrate is the insulating material that supports the transmission lines. In microstrip and stripline, the substrate is the dielectric slab onto which the strip conductors and groundplanes are plated and etched. Transmission lines have two important properties that depend on their geometry, inductance per unit length, and capacitance per unit length. The "characteristic impedance" of a system is calculated from the ratio of these two:

$$Z = sqrt(L/C) \quad \text{--- (Eq 2.1)}$$

Where, L is the inductance per unit length and C is the capacitance per unit length. Note that higher inductance translates to higher impedance, and higher capacitance translates to lower impedance. Further the units of length are not a factor. The units of inductance and capacitance must be self-consistent, such as pico-henries/foot and pico-farads/foot.

The inductance per unit length is mainly attributable to the diameter of the center conductor. Decreasing this diameter (keeping everything else the same) increases the inductance. As Equation 2.1 indicates, the characteristic impedance also increases. Another example is a microstrip. In this case, unit capacitance and inductance are inexorably linked together. A widening of the microstrip line decreases its inductance while at the same time its capacitance increases. Hence, wide lines are always lower in impedance than narrow lines for a given substrate height. As with a coaxial cable, the dielectric constant of the substrate has a large effect on capacitance; using a higher dielectric substrate will yield a lower impedance line, all other things being equal.

Relative and effective dielectric constants: The higher the dielectric constant, the higher the capacitor value. For an ideal parallel plate capacitor, the capacitance is calculated by:

$$C = E0ERA/D \quad \text{--- (Eq 2.2)}$$

Where, E0 is the permeability constant of free space, A is the area of the parallel plates, D is the distance they are separated, and ER is the relative dielectric constant of the material between the plates. E0 is equal to 8.854×10^{-12} farads per meter. The relative dielectric constant ER is the important parameter in microwaves. In microwaves, "dielectric constant" refers to "relative dielectric constant".

For electromagnetic radiation, the dielectric constant of the medium in which the wave is propagating is equal to ERE0. In a vacuum or in dry air, ER is equal to unity, and the signal travels at the speed of light. The speed of light in a vacuum, denoted "c" in textbooks, is 2.998 x 10^{10} centimeters/second, or 2.998 x 10^{8} meters per second, or about 186,000 miles per second. To put this speed into a physical context, it requires approximately 1.5 – seconds for a radio wave to travel from the earth to the moon.

Also, a rule of thumb is that E-M radiation travels one foot in one millisecond. The dielectric constant of a material can be used to quantify how much a material "slows" an electromagnetic signal. The velocity of the signal within any transmission line that is filled with a material of dielectric constant ER is computed by:

$$v=c/\mathrm{sqrt}(ER) \qquad \text{--- (Eq 2.3)}$$

So if a strip-line or coax transmission line is fabricated with a material having a dielectric constant of 2.2, the velocity of propagation is approximately 67% of the speed of light in free space. Similarly, because wavelength is proportional to velocity, the length of a quarter-wave transformer is also 67% of what it would be in free space. Thus by using materials of higher dielectric constant, distributed structures can be made smaller. One of the advantages of using GaA's (Gallium Arsenide) for microwave IC's (Integrated Circuit) is its dielectric constant of 12.9, which is appreciably higher than ceramics such as alumina, and most soft substrates.

In transmission lines using microstrip media, electric fields for the most part are constrained within the substrate. A fraction of the total energy however exists within the air above the board. The "effective dielectric constant" takes this fact into account. The effective dielectric constant of a fifty-ohm transmission line on ten mil alumina is approximately 7, which is less than the relative dielectric constant of the substrate bulk material (9.8). Another example of an effective dielectric constant includes strip-line circuits using substrates with different dielectric constants. To a first order, the effective dielectric constant would be the average of the two materials' dielectric constants. A third example is coplanar waveguide transmission lines with air above the substrate. In this case, the effective dielectric constant is approximately the average of the substrate dielectric constant and one (the relative dielectric constant of air). Thus the effective dielectric constant of CPW circuits on GaAs (ER=12.9) is approximately 6.5.

A decibel is the logarithmic ratio of two RF power or RF voltage levels (usually input and output levels). The conversion of linear ratios to dB is: 10xlog (power level2/power level1), or 20xlog (voltage level2/voltage level1)

Generally in microwaves, reference is generally made to power levels, not voltage levels. That is because microwave signals are usually measured in milliwatts, not millivolts. One can easily convert from power to voltage and vice-versa if the system characteristic impedance (usually 50 ohms) is known.

CHAPTER 4
OPERATION

2.4.1 Microwave measurements

The quantities such as frequency, signal level, impedance and attenuation, which are measured at microwave frequencies are essentially the same as those measured at lower frequencies. Given however that the wavelengths of the signals are comparable with the dimensions of the equipment, it is not possible to use the same measurement. In this section, measurement of these properties is considered. All measurements contain sources of error and it is important in any particular case to identify these errors and to estimate their magnitude.

2.4.1.1 Measurement of Frequency

One method of measuring frequency is to determine the wavelength of a standing wave in an air-spaced coaxial line. This wavelength is half the free-space wavelength. Therfore the frequency can then be calculated. The strength of the electric field on the line is sampled by a wire probe which protrudes a short distance into the space between the conductors. The signal is picked up as it passes via a detector diode and amplifier to a meter. The probe requires current to enable measurement, and consequently it impacts the accuracy of the measurement. As the probe is moved along the coaxial line, maxima and minima of the standing wave are detected, as shown in Figure 2.4. For a perfect standing wave, the minima are zeroes and their positions can therefore be determined with considerable accuracy. In practice there is some uncertainty about the position of a minimum because the signal detected falls below the noise level of the detection system. This error can be reduced by measuring the positions of as many minima as possible. In this way several different values for the wavelength can be obtained and the average taken to reduce the standard deviation of the measurement. This approach has the advantage of directness but the accuracy which can be obtained is low (perhaps 0.1% at best) and the measurements are time consuming.

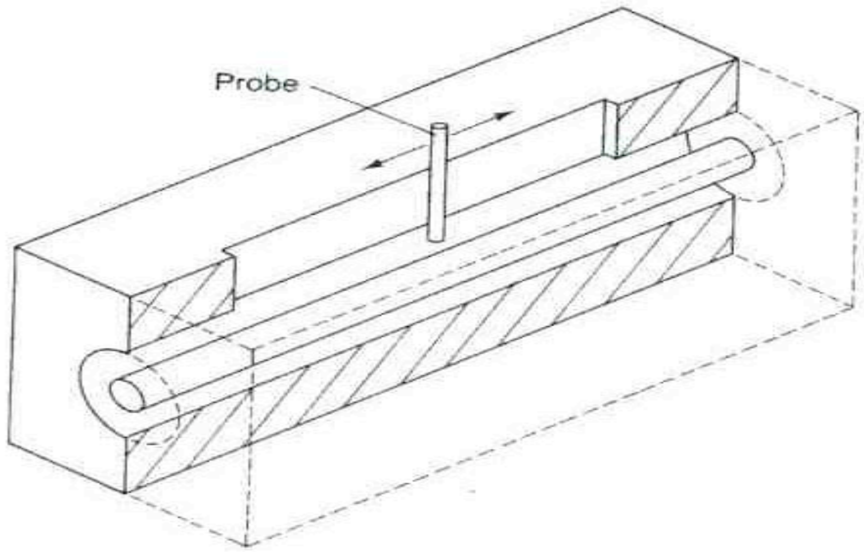

Fig. 2.4: *Sectioned view of a slotted section of coaxial line*

For most microwave laboratory measurements it is much better to have a direct reading of frequency. Originally this was achieved by using a calibrated resonant cavity. By careful design of the cavity, the Q factor could be kept high enough to give a sharp response. The tuning mechanism could also be made to give a direct reading of frequency. Cavity resonance wave meters, as these devices are known, are still used but they have been generally replaced by microwave frequency counters. The accuracy of a cavity resonance wave-meter is typically 0.1%.

Microwave frequencies are too high for the use of the direct counting technique, which can be employed at lower frequencies. This problem can be circumvented by mixing the signal to be measured with that from a crystal controlled local oscillator. If the local oscillator wave form is rich in harmonics, then the output from the mixer will be a set of frequencies given by:

$$f_i = f_x - nf_1 \qquad \text{----- (Eq 4.1)}$$

Where n is the order of the harmonic and it is assumed that $f_x > nf_i$. The mixer output is fed through a bandpass filter which selects just one frequency out of the set generated. This frequency can be chosen to be low enough for it to be measured with a conventional counter. Since f_1 is known, it is then possible to compute the source frequency f_x.This assumes that n can also be determined. To do this, a second measurement is taken with the local oscillator frequency reduced to f_2 with the offset (f_1- f_2) known, the unknown frequency is then given by:

$$\begin{aligned} f_x &= nf_1 + f_{i1} \\ f_x &= nf_2 + f_{i2} \end{aligned} \qquad \text{----- (Eq 4.2)}$$

and it is assumed that the frequency offset is small enough so that the same harmonic is responsible for the output measured. Eliminating f_x from these two equations gives:

$$n = \frac{f_{i2} - f_{i1}}{f_1 = f_2} \qquad \text{----- (Eq 4.3)}$$

so n can then be computed. The unknown frequency can be found by substitution back in equation 4.2. In practice it is necessary for the method to be a little more complicated to take into account the possibility that one or both of the harmonic frequencies may lie above the unknown. It is also necessary to take steps to ensure that the measurement is accurate even if the incoming signal is frequency modulated.

2.4.1.2 Measurement of power

When the detection of a microwave signal is required, a semiconductor diode of the kind shown in the Figure 2.5 is used. At frequencies above 1 GHz, it becomes difficult to match the diode satisfactorily because its impedance varies with power level. Alternative techniques based on converting the microwave power into heat are then used.

At the power levels (a few milliwatts), the detecting element is either a thermistor or a bolometer. A thermistor is manufactured from a mixture of semiconduting oxides and has a negative temperature coefficient of resistance. A bolometer is a thin film resistor deposited on an insulating substrate. Bolometers have response times of less than a millisecond but are very easily damaged through exposure to high levels of power.

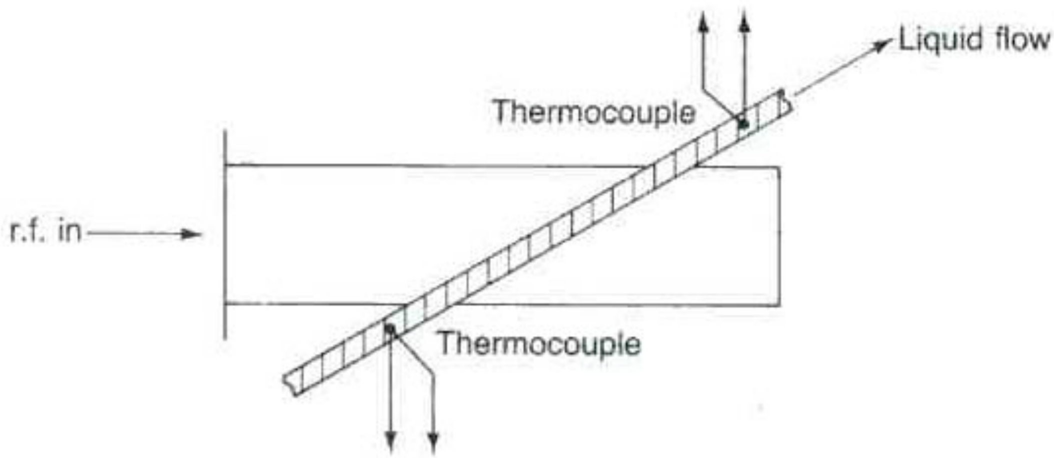

Fig. 2.5: *A liquid flow calorimeter of measuring microwave power*

Thermistors are more rugged but have response times of up to a second. In either case the resistance of the sensing element varies with ambient temperature as well as with the microwave power absorbed. A power meter head therefore typically incorporates two matched thermistors or bolometers which are connected to two arms of a Wheatstone bridge. Only one of the devices is exposed to microwave power. The result is that the balance of the bridge is unaffected by changes in ambient temperature. The bridge is balanced automatically and the output displayed directly in milliwatts on a meter.

At higher power levels (a few watts) the power meter head must be protected from the full power by a calibrated attenuator, which is capable of dissipating the full power. An alternative technique is to use a directional coupler to sample the power.

Direct measurement of high power levels is carried out by using a continuous flow calorimeter as shown in the Figure 2.5. The input power (normally in a waveguide) is absorbed by liquid flowing in a dielectric tube. The tube crosses the guide at an oblique angle to ensure a good match. Often water flowing in a glass tube is used. The temperature rise in the liquid is measured by a pair of thermocouples. The device is calibrated for a particular flow rate, which is carefully controlled. Alternatively an electric heating element is used as a calibrating heat source.

2.4.1.3 Measurement of gain and loss

In many microwave systems it is necessary to know the gain or loss of each component in order to compute the system performance. These quantities are commonly measured by comparison with standard attenuators. The two possible configurations are (radio frequency) r.f. and (direct current) d.c. substitution. In both cases there is a signal source, a standard attenuator, a detector and a signal level indicator. In r.f. substitution, the attenuator is a rotary-vane attenuator in a waveguide or a switched attenuator in a coaxial line. In d.c. substitution, the attenuator is in the form of a switched network of precision resistors. The indicator is a meter or an oscilloscope. The procedure in either case is to set the signal level to a convenient value with the device under test, in position. The device under test is then removed, and the attenuator adjusted to return the signal back to the same level. This method avoids errors caused by non-linearity in the detector.

In general the gain or loss measured is made up of two components that result from gain or attenuation inherent in the device and that caused by reflection at mismatches. Since the device under test can never be perfectly matched, some of the input signal is reflected back towards the source at both the input and the output terminals. Unless the source is very well matched to the connecting transmission lines, there will be multiple reflections of the signal producing errors which vary with frequency. A common practice is to put a 10 dB (deci Bell) attenuator (a ‘pad’) between the source and the system to reduce the possibility of multiple reflections.

Frequently the measurement is to be made over a band of frequencies. The signal source would then be a sweep oscillator set to sweep repeatedly over the band and the output could be fed to an x-y plotter to provide a permanent record. A simpler r.f. substitution system might use a power meter or a VSWR meter as a detector. Because the output of the oscillator and the sensitivity of the detector vary with frequency, it is necessary to produce a set of calibration lines with the attenuator. The performance of the device under test can then be deduced by interpolation between them. Commonly the oscillator is balanced by an external or internal feedback loop to reduce the variation of its output power with frequency.

Better plots of the gain or loss against frequency can be produced if a scalar network analyzer system is used. The general arrangement is shown on Figure 2.6. The signal from the sweep oscillator is sampled by high directivity directional couplers before and after passing through the device under test. The signals in the coupler side-arms are detected and passed to the scalar analyzer, which is able to display the two signal levels and their ratio in dB versus frequency. The output from the scalar analyzer can be fed to an x-y plotter to provide a permanent record of the performance of the device under test. The signal-to-noise ratio of the system is enhanced by square-wave modulation of the signal and the use of a tuned amplifier in the scalar analyzer.

This arrangement removes errors produced by variation in the output of the oscillator by measuring the ratio of the signal levels. It is still liable to errors from a number of other sources including the finite directivity of the couplers and any differences in the frequency responses of the couplers and the detectors. Systematic errors, which are independent of frequency, can be eliminated by removing the device under test and setting the zero level on the analyzer. Some systems incorporate a storage normalizer, which is able to store the characteristics of the system in the absence of the device under test and correct for them when the result of the measurement is displayed. It is tempting to regard the results produced by such a system as being free from errors though this can never be the case. For example, if the device under test has a high reflection coefficient, the measurements will be appreciably affected by multiple reflections between it and the source (which can never be a perfect match).

2.4.1.4 Measurement of return loss

A simple modification to the system shown in Figure 2.6 permits the measurement of the return loss of a component directly. The two directional couplers are set to measure the incident and reflected power in the transmission line connected to the input port of the device under test. The arrangement, known as a reflectometer, is widely used for the adjustment of the matches between the incident and reflected power of devices during manufacture.

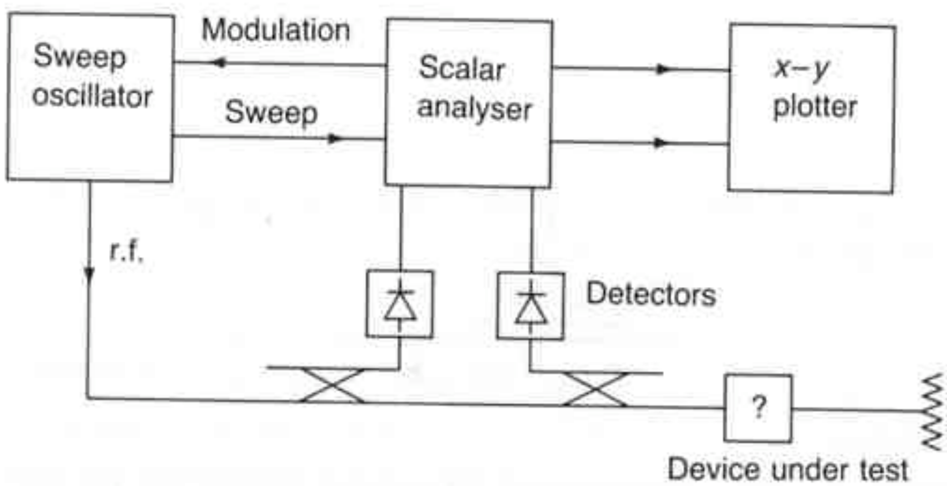

Fig. 2.6: *Block diagram of a reflectometer for measuring reflection coefficients*

2.4.2 Microwave Processing

There are several reasons for a growing interest in microwave processing over conventional sintering and heating methods. These reasons include the potential for significant reduction in manufacturing costs and improved mechanical properties. By improving the mechanical properties of the materials, the performance of the product is enhanced. Use of microwave energy for sintering of materials is a relatively new development in material processing but its use is growing. Microwave energy for industrial applications has been used for quite some time; but only in processing applications where it is used in meat tempering, bacon cooking, rubber vulcanization and food preparation. Also, in the ceramic industry, microwave processing has been used in process control, drying of ceramic wares and calcinations. Microwave plasma is used in decomposition of gaseous species and sintering of oxide ceramics. The newest category of ceramic applications is absorption of microwave energy by white solid ceramics as a source of internal heating. This application was first championed at Penn State's IMRL in the early 1980’s and has been extended this to "black" non-oxide ceramics.

At present in the ceramic industry most powder consolidation including those using carbides is carried out by thermal sintering, hot pressing or hot isostatic pressing (HIP). A major problem with these techniques is that the time required for consolidation at high temperatures is quite long, and as a result, undesirable coarse microstructures with grain boundary impurity phases are invariably formed. Also, long consolidation by conventional methods is not cost-effective. Therefore, novel and efficient consolidation processes are very attractive for the industry. The microwave processing of ceramic materials has many advantages over the conventional methods. Some of these advantages include time and energy savings, very rapid heating rates (>400°C/minute), considerably reduced processing time and temperature and better microstructures that result in improved mechanical properties.

Many traditional and modern ceramic materials have been processed using microwave methods. Alumina, silica, zirconia, zinc oxides, SiC, perovskites, Si_3N_4, etc. have been processed successfully by many researchers in various laboratories. Transparent, white, and porous ceramics of hydroxyapatite, a biomaterial, were also successfully fabricated using microwaves in a matter of few minutes. Oxide ceramic composites with ZrO_2 as a primary phase were also sintered in a microwave field with improved density. A new low expansion material, NZP, was also processed in a microwave field at significantly lower sintering conditions. In almost all these materials that were fabricated by microwave processing, the sintering characteristics and mechanical properties were significantly improved, and, at the same time, processing temperatures and times were dramatically reduced.

Investigators at Alcan International Ltd. have devised means to process Si_3N_4 tool bits using a microwave technique. Their results demonstrated that microwave processed tool bit produced much more uniform toughness than the tool bits commercially available, and also, the machining test resulted in superior performance of the microwave processed tool bits. This clearly shows that non-oxides can be successfully processed in microwave with superior performance over the conventional product.

2.4.3 Principle of Microwave Sintering

Microwave heating is fundamentally different from conventional radiant heating. In the microwave process, the heat is generated internally within the material instead of originating from external heating sources, and if the material is coupled to the microwave energy, the heating is volumetric and rapid. Typically, microwaves are electromagnetic radiation with wavelengths ranging from 1 mm to 1 m in free space and frequency between 300 GHz to 300 MHz, respectively. However, microwaves of 2.45 GHz frequency are generally used for the industrial and scientific applications. The microwaves can be transmitted, absorbed, or reflected, depending upon the material type.

Most materials transmit and/or absorb microwaves to varying degrees, the nature of the interaction being largely characterized by the dielectric properties of the material. When microwaves penetrate and propagate through a dielectric material, the internal electric field generated within the affected volume induce translational motions of the free or bound charges (e.g. electrons or ions) and rotate charge complexes such as dipoles. The resistance of these, induced motions due to inertial, elastic, and frictional forces, causes energy losses and attenuates the electric field. As a consequence of these losses, volumetric heating inside the solid material occurs.

Due to this volumetric heating, the thermal gradients and the flow of heat in microwave-processed materials are the reverse of those in conventional heating. Microwave heating is instantaneous (on/off) with power. Consequently, microwave field makes it possible to heat both small and large shapes very rapidly, uniformly, and efficiently. This is important in case of Tungsten carbide/Cobalt (WC/Co) based products where undesired grain growth can be prevented by rapid heating and short sintering periods. These features, when properly controlled, result in better product uniformity, faster production throughput, less factory floor space, and reduction in wasteful heating (i.e. furnace walls, conveyor belts and kiln furniture). All these factors are highly favorable in the processing of WC/Co based components for a drilling system.

2.4.3.1 Controlled Atmosphere Microwave System for WC/Co Processing

A microwave system typically consists of a generator to produce microwaves, a waveguide to transport the microwaves, an applicator (a cavity) to manipulate the microwave field for a specific purpose, and a control system for tuning power and monitoring the temperature etc. Single-mode or multimode systems are readily available. Single-mode systems have limited utility because of small volume over which the microwave field is uniform and hence only small parts can be processed very effectively. In a multimode system, large areas of uniform field can be designed and therefore large samples as well as multi-sample runs can be processed very effectively and uniformly. To accommodate Tungsten carbide/Cobalt (WC/Co) and diamond based materials, the typical microwave systems would need drastic modifications, as explained below.

In a regular microwave system, generally a simple microwave unit (similar to that used in kitchen) is used and most ceramics are processed in air. However, for WC based materials an inert or reducing atmosphere is required. For this purpose, a new system specifically to process WC/Co, other non-oxides, and diamond-composite based materials has been designed. This system is capable of processing shapes of various kinds and sizes.

For uniform and homogeneous sintering of the work piece, a uniform temperature distribution and proper heating and cooling rates are very important. The microwave applicator is designed in such a manner that in the central portion of the chamber, a highly intense and uniform microwave field is developed. This along with proper insulation and secondary heating provides a uniform temperature across the sample(s). The atmosphere inside the chamber is also controlled. The temperature is monitored either by a pyrometer through a view-window or by inserting a thermocouple in the microwave chamber. The optimized processing conditions of microwave sintering for various sizes and shapes of the specimens must be carefully developed by a series of systematic testing and processing of the test-pieces.

2.4.3.2 Fine Grained Tungsten Carbide (WC/Co) Cermets

Hard metal composites due to their unique combination of hardness, toughness and strength, especially the tungsten carbide (WC) based composites, are universally used for cutting tools and drills, machining of wear resistant metals, mining, geothermal, oil and gas drilling. They are also required to possess highly abrasive and wear resistance properties. Conventional methods for sintering WC with Cobalt (Co) as a binder phase involve high temperature and lengthy sintering cycles of the order of a day. These are very energy intensive. Consequently, the production costs of these materials are quite high. Furthermore, in the conventional sintering method, the carbide specimen must be subjected to very high temperatures (up to 1500°C) for these long periods in order to achieve a high degree of densification/sintering. Such conditions favor undesirable WC grain growth in the presence of Co melts. Consequently, the mechanical strength and hardness of the tool is diminished. It is a well known fact that finer microstructures provide superior mechanical properties and longer life of the product.

Researchers have found that certain materials can be incorporated into the WC matrix to help prevent grain growth during the sintering process. Additives such as titanium carbide (TiC), vanadium carbide (VC) and tantalum carbide (TaC) can be used for this purpose, but unfortunately such additives deleteriously affect the mechanical properties of the tools and add substantially to the overall cost of the tool. Also, use of nanometer size WC/Co powders has also been proposed to make these tools. But, the high cost of nanopowders, their large scale production, and again maintaining the nanostructure during conventional sintering are the principle factors that are considered unattractive to commercial manufacturers. However, using microwave techniques developed at the Pennsylvania State University for sintering of WC based tools, the grain growth can be reduced to a minimum without adding any grain-growth inhibitors as a consequence, a very fine initial grain size can be retained and materials with better mechanical properties can be synthesized. Also, the process is accomplished in a single step. Moreover, the process is rapid, highly energy efficient, cost effective, and environmentally friendly

Tungsten Carbide is by far the most important hard phase in the cutting and drilling industry. Several billions of dollars of WC + Co tools are used annually. The next section discusses the implementation of microwave generated materials in drilling.

2.4.4 Drilling System

The process of drilling into the earth and acquiring natural resources from under ground such as oil, gas, minerals, water, coal, etc., is nearly as old as human civilization. The conventional rotary drilling methods, however, were developed only about a hundred years ago. In the last few decades, many variations of this rotary drilling system have been developed to make the entire drilling process cheaper, faster, safer, and more efficient.

Main components of a baseline or a typical petroleum and gas drilling system are a derrick or mast (a steel tower), drill pipe/string, and bottom hole assembly (BHA) consisting of bit, stabilizers, and other drill tools. The drill-bit which rotates to break or reduce the rock and advances the hole, is usually either a roller-cone, which crushes the rock as the cone turns as their teeth successively come in contact with the unbroken areas, or a drag bit which shears the rock in the same way that a machine tool cuts metal. The design and the quality of the material used in these bits are very important to the performance of the bits.

This analysis deals with the drill bits and, in particular, components, made of diamond and cemented tungsten carbide. The efficiency and performance of a drilling operation depends upon many factors, and is judged in terms of rate of penetration, safe operation, and effective cost. It is estimated that if a normal bit life of 90 hours is increased by 20 to 30 percent, the savings in the entire drilling operations will be hundreds of thousands of dollars per operation. By using the technology of microwave processing, the performance of the carbide tool and diamond composites in the bit will be improved, and the life of a bit, as well as its rate of penetration, can be substantially increased. This report focuses on the cutters and other abraded surfaces,that can be made more cost/performance effective by either utilizing materials produced through microwave processing and/or adopting diamond composite materials approach. This improvement in performance results from the replacement of conventional methods and materials, which now have limits in their performance and need to be upgraded.

Some Recent Results on Exploratory Experiments

In a preliminary study, several researchers at Penn State were able to successfully sinter several WC (6 and 12% Co) green samples. The well sintered specimens had a fine and uniform microstructure ($\simeq$ 1 micron size grains) with very little grain growth when sintered at 1250 - 1350 °C for only 10 - 30 minutes. These conditions are significantly lower than conventional sintering conditions. The hardness measurements made on microwave processed specimens gave values as high as 93 Rockwell A for samples sintered for only 10 minutes at 1350°C. This is significantly higher than that achieved in conventionally sintered bodies with the same Co content and sintered under same temperature and time conditions.

These data indicate that fully dense WC/Co material in a microwave process can be obtained in 10 minutes at temperatures of 1250 °C (Co: 12%) and 1350°C (Co: 6 %). These processing conditions are radically lower than that typically used in conventional sintering of WC/Co material. These preliminary data suggest that microwave processed samples of WC/Co may have the potential of substantially better performance and longer lifetime. Most importantly, the method will also be effective because the technique utilizes much less total energy and time than conventionally employed methods; it still produces a product with better microstructure and thus the potential for improved performance and longer life. Table 1 below provides a comparison between microwave and conventionally processed WC/Co cermet. Cermet by definition is a powder metallurgy product consisting of ceramic particles bonded with a metal.

	Microwave	Conventional
Sintering Temperature (°C)	1300	1400-1500
Total Cycle Time	90 min	12-24 hrs
Sintering Time (Minute)	10	60
Density (% T.D.)	99.8	99.7
Average Grain Size (m)	0.6	2
Bending Strength (MPa)	1800	1700
Hardness (Rockwell A)	93	91

Table 2.1: *Comparison of microwave and conventionally processed WC/Co based materials*

CHAPTER 2.5
APPLICATIONS

This chapter will discuss the applications of microwaves in various fields. In the prior two decades, its primary applications have been in electrical and electronics sectors. Its expansion has been significant in the fields such as the oil and medical industries.

Microwaves, like light, have the property of propagating along a straight line. For long distance communications, therefore, it is necessary that repeaters be used within line of sight to receive, amplify and retransmit the signal. A spacing of about 40-50 km between repeaters is typical for relatively flat terrains. The point-to-point communication systems include the long-distance telephone and TV repeater stations, communications for operation and control of electric power transmission systems, toll roads and railways, oil pipelines, telemetering, public-safety communications and earth-to-space communications.

For low angle launching of microwaves, the gradual earthward bending of the beam of atmospheric refraction can be used to communicate to distances beyond the line of sight. The phenomenon known as tropospheric refraction replicates primarily on a reducing atmospheric density and consequently refractive index as a function of height. Weak but reliable Microwave links can be established on this principle for distances of several hundred kilometers. Such links are, however, subject to fast-fading due to multi-path transmission, and slow fading due to the changes in the gradient of the atmosphere. In spite of the advantages of longer distance, tropospheric propagation is consequently not preferred for higher reliability communication links.

Microwave ranging from S to Ku bands are commonly used for ground based communication purposes. For space-to-space communications, however, millimeter waves are preferred because of the more compact antenna and waveguide systems. There is a recent move to consider the use of K-band frequencies for ground-to-satellite communications to alleviate the congestion at lower Microwave frequencies. For this application the propagation losses are considered acceptable even for high humidity and rainy conditions because of the limited extent of the atmosphere through which the signals must pass.

Because of the larger atmospheric absorption, the 60-GHz band is quite useful for secure communications for short distances and is relatively unsusceptible to jamming. For very long distance communications, the lower range of Microwaves, L and LS bands, are preferred because of the availability of higher powered transmitters at these bands.

There are several other traditional applications of microwaves. These applications include radar (including airborne, marine and ground radars), aircraft altimeter and guidance systems, intercontinental telephone and television communications via satellites, and reconnaissance mapping of the ground from the air even in the presence of fog.

2.5.1 General Microwave Applications

The proceedings of the 8th International Conference in Microwave Engineering discuss the various applications of microwave technology. These applications include:

- Hyperthermia in cancer therapy: technical and clinical aspects
- Industrial applications of microwaves
- Microwave satellite reception technology
- Low cost GPS-receiver – A satellite navigation receiver for the global-positioning-systems.

2.5.1.1 Hyperthermia in cancer therapy: Technical and clinical aspects

The possibility of significant antitumor activity associated with temperatures over 40^{o}C was first documented by Busch in 1866. Since that time, several investigators have shown that heat alone can cause regression and cure of malignant tumors and that the effect of hyperthermia is related to both duration and level of heat. In recent years a rebirth of interest in hyperthermia was generated by results gained in several medical specialties by combining heat with irradiation and/or chemotherapy. Discussed are techniques for producing hyperthermia with electromagnetic fields. Using these techniques a broad spectrum of malignant tumors can be treated including skin tumors, tumors of the pelvis and thorax, and tumors as small as malignant intraocular neoplasms. Advances in hyperthermic tumor treatment are expected in future generations of ultrasonic and electromagnetic technology, such as improved means for high accuracy of tumor localization and heat delivery. Further work to evaluate thermal toxicity and thermotolerance, as well as sequencing and fractioning of hyperthermic and radiation doses, is indicated to maximize the potential for combined use of these treatment modalities in cancer therapy.

2.5.1.2 Thermo-radiotherapy in cancer therapy

The rationale for using hyperthermia in combination with irradiation is based on several experimental findings and it was predicted by several investigators that the therapeutic effect of combined hyperthermia and radiation might be synergistic. Experimental results demonstrating this synergy of heat and radiation showed that heat delays or inhibits repair of both sublethal and potentially lethal irradiation damage. Enhanced therapeutic response to both modalities combined was also shown on tumor cells in different stages within the reproduction cycle. Radiation is most effective during mitosis and early S-phase, whereas radiation-resistant late S-phase cells are heat sensitive. Radiation-resistant hypoxic cells were found to be more sensitive to heat damage than oxygenated cells. This is most likely related to heat-induced environmental changes, such as decreased blood flow, low pH, and poor cell nutrition.

Based on experimental heat and radiation application on both normal and tumor cells Robinson defined the thermal enhancement ratio (TER). TER for normal tissue was determined to be unity at 40.3 ^{o}C and increased to 2.06 at 43 ^{o}C. when heat was applied to tumor tissue, TER at 40.4 ^{o}C was again unity, but increased to 4.33 at 43 ^{o}C. Experiments with various temperatures showed that the slopes of the TER of both normal and tumor tissue were linear. Based on these results a therapeutic gain factor could be defined as the TER of tumor divided by the TER of normal tissue which proved to be useful in oncology to describe the synergistic effect of hyperthermia and ionizing radiation.

Cancer therapy both by hyperthermia and radiation usually is given by a fractionated treatment schedule. However, after repeated heat application tumor cells were found to become resistant to further heat treatments given shortly after the initial treatment. This physiological phenomenon was called thermotolerance (thermal resistance), and was studied extensively by several investigators. The heat resistance of tumor cells was found to be most pronounced approximately 5 hours after therapy. Depending on the tumor cell type, a slow decay of this resistance was encountered during a period of 72 to 120 hours, after which the cells were no longer thermally tolerant. The knowledge of thermotolerance as a counterproductive effect in hyperthermia therapy is important for clinicians in designing fractionated hyperthermia and radiation schedules.

2.5.1.3 Thermochemotherapy

Similar to radiosensitization of malignant cells through heat, many anticancer agents like bleomycin, adriamycin, and cisplatin become more cytotoxic at increased temperatures. When compared to 37 ^{o}C used with chemotherapy, hyperthermia increases the permeability of all membranes, allowing a greater percentage of drugs to penetrate malignant tumor cells [2.49]. Hyperthermia offers the potential for reducing the required drug dosage. By reducing the drug dosage, the side effects of these drugs can also be mitigated.

However, the therapeutic enhancement of cytotoxic agents combined with hyperthermia is not uniform to all tumors treated and all drugs used. The activity of some drugs is increased at all temperatures (e.g. cisplatin), while for others (e.g. bleomycin) 43 ^{o}C represents a borderline, below which no increased cytotoxicity is encountered.

As in thermoradiotherapy, thermotolerant cells respond differently to some drugs than do cells that have not been preheated. Additionally, the effect of thermochemotherapy is also a function of the duration and degree of heating. Based on numerous experimental studies the first clinical trails were performed using hyperthermia and drugs in combination. The drugs were infused either regionally or systematically while heat was applied either locally or as whole body hyperthermia. At this time, the promising data published are still scanty but they allow the conclusion, that similar to thermoradiotherapy the potential of hyperthermia to potentiate the therapeutic effect of anticancer agents has clearly been demonstrated.

2.5.1.4 Technical aspects in hyperthermia

Several techniques to deliver hyperthermia to malignant tumors have been used since the beginning of this century. These include whole body heating, regional perfusion of extremities, local heat induction by electromagnetic fields and radiant heating by focused ultrasound. Due to significant improvements to the technology associated with heat application within the last decade, electronically generated hyperthermia has gained far more acceptance compared to formerly used direct heat application, whether by water bath, heated air jet or extracorporal perfusion heating. For electronically induced heat these approaches can be used: a) (frequency range 200-3000 MHz), b) ultrasound

hyperthermia using electronically generated high-frequency mechanical vibrational tissue interaction (frequency range 1 - 3 MHz).
According to their physical differences, the techniques mentioned above are used to fulfill different experimental and clinical requirements. Radiofrequency applicators and microwave applicators can be used in a non-invasive way to induce local hyperthermia in malignant tumors located with in 3-4 cm of the body surface. Examples include skin tumors, metastases of superficial lymph nodes, and tumors within the gastrointestinal and urogenital system. Both techniques can also be used in attempts to induce hyperthermia transmitted through surface structures within tumors located deeply within the human body. During the past 5 years, third invasive technique has gained some acceptance and utilizes implanted interstitial electrodes within deep seated malignancies. Designs and performances of current types of radiofrequency and microwave applicators for all techniques mentioned above were recently reviewed by Hand and Hind, James, Henderson and Johnson, and Strohbehn and Mechling.

2.5.1.5 Thermoradiotherapy in malignant eye tumors

Choroidal melanoma is the most common primary intraocular malignancy seen in adults. Within the last 15 years radiotherapy using radioactive scleral plaques has established satisfactory results. Treatment failures are associated with the relatively low radio sensitivity of intraocular melanomas, and include dose related complications, such as cataracts, vasculopathy of the retina and optic nerve, and neovascular glaucoma. Thus, adjuvant hyperthermia application, which could increase the efficacy of radiation, could be useful in local melanoma therapy. In experimental studies both focused high intensity ultrasound and microwave electromagnetic heating were applied to normal and tumor bearing rabbit eyes and athymic mice with human chorodial melanoma.

In ultrasound hyperthermia a 4.75 MHz transducer was employed with the energy applied transsclerally to the tumor via a water bath system. In those cases where microwave hyperthermia was used, local heating was produced by a 2.45 GHz disc antenna sutured to the sclera next to the intraocular tumor. In both treatment modalities, combined hyperthermia and irradiation did not result in increased scar formation or other complications in any eyes treated. Encouraging results with both ultrasound and microwave hyperthermia have prompted initial clinical investigations in selected patients with intraocular malignant melanoma.

Analysis of current electromagnetic and ultrasound energy application demonstrates that there is no universal heating modality that can be applied for any given clinical hyperthermia situation. Various techniques are required to cover a broad range of clinical hyperthermia needs. Early clinical studies have confirmed that hyperthermia is synergistic with radiation therapy, and has the potential for synergy with chemotherapy. These studies have further demonstrated that this combination can be used with acceptable toxicity. Advances in hyperthermia tumor treatment are expected in future generations of ultrasonic and electromagnetic technology, such as improved means for tumor localization and heat delivery. Further work to evaluate thermal toxicity and thermotolerance, as well as sequencing and fractionation of treatment doses, will maximize the potential of thermoradiotherapy and thermochemotherapy in the treatment of cancer.

2.5.2 Industrial applications of Microwaves

Typically, the definition of microwaves in terms of frequency range is 300 MHz to 300 GHz. In terms of wavelengths, microwaves typically vary from 1-mm to 1-m. In these ranges microwaves have application for use in the following[2.49]:

1) Terrestrial radio links for transmitting telephone signals, telex signals, data signals and tv signals,
2) Satellite connections for the same purpose,
3) Radar, some navigation systems and telemetry transmissions,
4) Industrial and medical applications,
5) Radio astronomy,
6) Microwave ovens in private homes,

Reasons for using microwaves include:

a) A very large bandwidth, which is necessary for the transmission of a greater number of telephone signals or tv signals. Transmission of these signals require a higher carrier frequency than the modulation frequency,
b) Point to point connections, as used in radio and satellite links, and direction finding as used in radar applications, require shaped narrow beams of radiation. This is only attainable with very short wavelengths, because there is a relationship between beam width, wave-length and antenna size, Transparency of fog and clouds in the atmosphere and of the ionosphere is also an important factor to be considered in these applications. At microwave frequencies, its depth of penetration and the high loss coefficient of water are other reasons for some industrial and medical applications, which use the heating of material with high water content.

2.5.2.1 Application without radiation

2.5.2.1.1 Heating and Drying of Industrial goods

For heating or drying, microwave power levels of100-watts to 100-kilowatts are required. These levels of power can be produced by magnetron vacuum tubes, which have a relatively high efficiency of approximately 50%. For power levels, such as 300W to 1kW, as used with microwave ovens in domestic applications, these magnetrons are quite inexpensive. The typical frequency is 2.45 GHz. It is necessary to minimize the fifth harmonic to avoid interferences with the DBS-frequencies, which are in this range. The materials to be heated like grain, nuts, plastics, coal granules or food must be enclosed in a metal box, which acts mostly as an oversized resonator. To prevent ‘hot spots’ inside this box and to produce on average a homogeneous distribution of the microwave field, rotating antennas or rotating metal vanes are used, to alter the field distribution slowly. To feed the resonance box with the microwave, a waveguide of around 86 x 43 mm is typically applied. The coupling to the magnetron and the connection from the wave-guide to the resonance box is similar to the waveguide-coaxial cable-transition.

Further, it should be noted that the radiation outside the heating box can not exceed the value of 10 mW/cm^2, which for safety reasons is the maximum permitted power density for health reasons. Doors to the heating box are equipped mostly with quarter wavelength chokes on the margins and during the opening of the door; the power generator is automatically switched off. In the case of continuously moved goods as by conveyor belts, the openings to the outside must have a stopband filter or alternatively equipped with waveguides ‘below cutoff’.

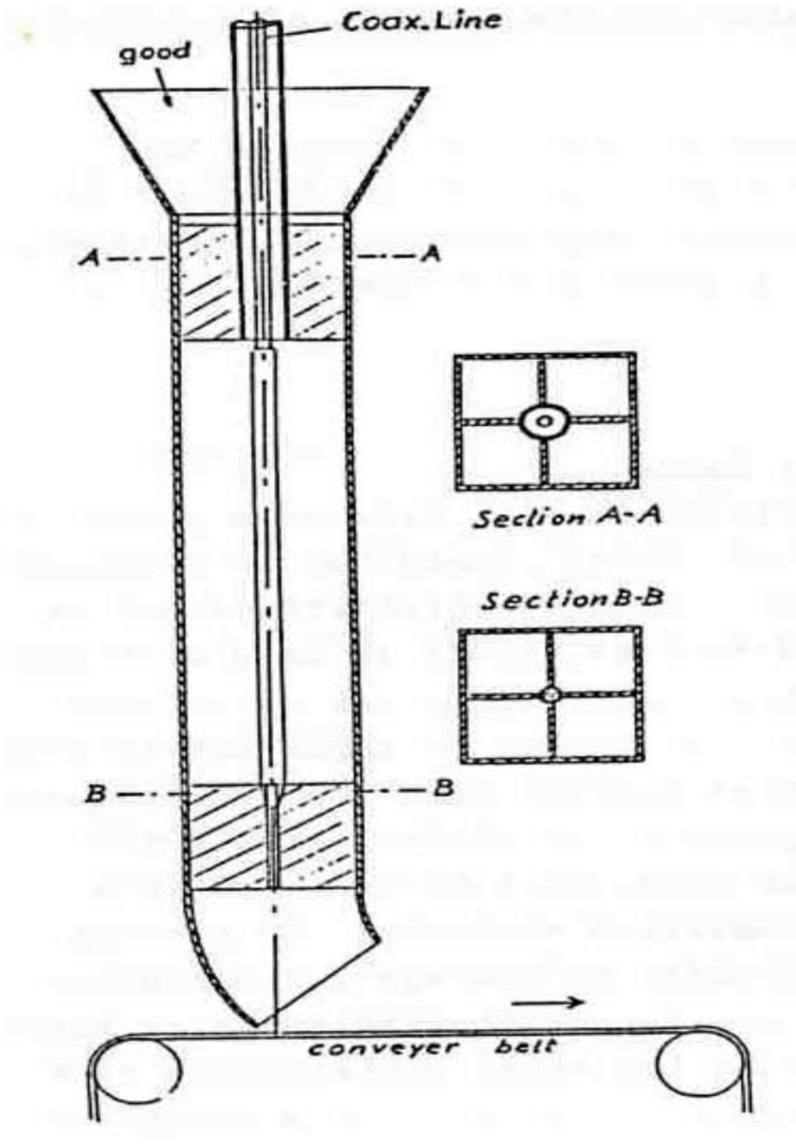

Fig. 2.7: *Waveguide section*

2.5.2.1.2 Microwave plasma – Heating and Spectroscopy

Heating of plasma using microwaves can produce very high temperatures. For experiments in nuclear fusion reactors, very high microwave power – between 100 kW and 10-100 mW are applied or planned to be applied in the frequency range of a few GHz to 140 GHz. The sources for these high power levels are klystrons or gyrotrons. The status of the plasma in the fusion reactors is indicated also by microwave measurements of reflection and transmission in the mm – wave range, which is termed "plasma diagnosis".

Another application of plasma, which is excited by microwaves, is the optical spectroscopy of gas impurities in the plasma. For this purpose normal air under atmospheric pressure, in which water with dissolved impurities is sprayed, is blown in a resonator and heated very quickly. The spectral lines of the optical radiation of this very hot plasma indicate the impurities. The term "Microwave Spectroscopy" is used in another sense for measuring properties of materials in the microwave frequency range, e.g. by seeking molecular resonance frequencies.

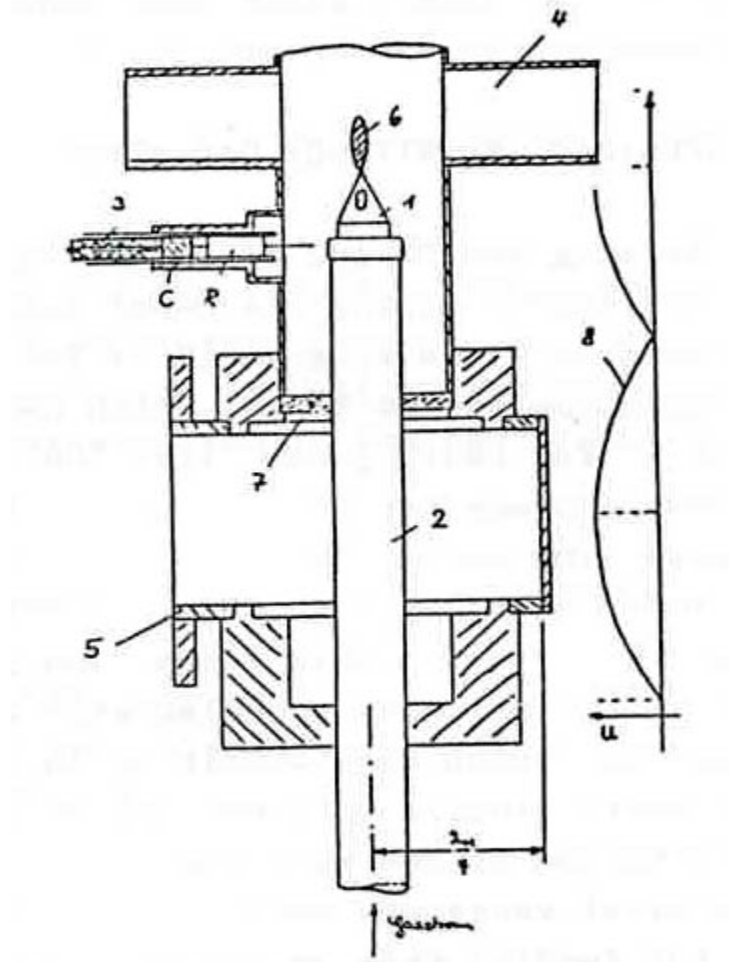

Fig. 2.8: *Resonator for Microwave plasma*

2.5.2.2 Applications using the continuous wave radar principle

a) Without Modulation

- **Traffic radar for speed measurement**

Since 1958 various types of traffic radars used by the police for checking the speed of automobiles are well known in Germany. The utilized frequency is 9.41 GHz or more recently, 34.3 GHz. The measurement is based on the Doppler effect and homodyne mixing. Counters for the display extract the frequency difference between transmitted and received signals. The necessary distinction between arriving and outgoing traffic is made by “quadrature” mixers, which consist of two diodes, mounted in a distance of 1/8 wavelength. This quadrature mixer produces two low-frequency signals with a phase difference of 90^o. So the sign of the Doppler-frequency can be evaluated.

Newspapers have reported the possibility of measurement error when using these devices. The probability of error is quite small and would result from interference from sources such as radar or intrusion alarm systems. Also measurements via reflected beams or “double way reflections” correspond mainly to a theoretical idea. To avoid the causes of theoretical error, radar sets realize modifications such as a comparison of measurements and annulment of a result with high acceleration.

- **Measurement of the speed of vehicles, such as trains, tractors and cars**

It is sometimes impossible to evaluate speed or distances traversed using the rotation of wheels where slippage exists between the wheels and ground. This is often a function of weather conditions. Currently, there is an increasing number of 4-wheel driven cars. Also locomotives have slip ratios exceeding 30%. The measurement of speed and distance using a CW-Doppler-radar can be performed with an antenna directed toward the ground. The Doppler frequency depends on the cosine of the angle between radiation and surface motion. Using a horn antenna with a broad opening angle in the near field the Doppler-spectrum is quite extended and the accuracy of the speed determined is poor or requires significant integration. Some years ago, a special near field antenna for 35 GHz was developed. The antenna consists of a wave-guide with a longitudinal slot, which is slightly off the centerline. This permits radiation continuously along the waveguide with a constant angle depending on the ratio of guide wavelength and free space wavelength.

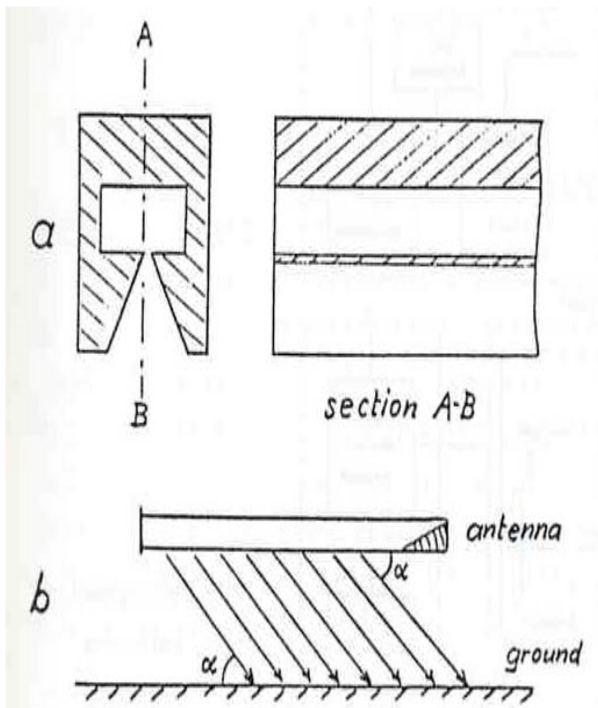

Fig. 2.9: *Waveguide antenna for near field application*

- Motion Detection Devices

Several motion detectors, mostly in the X-band are used for purposes, such as intrusion alarm systems, traffic counters, and door openers. Some are comparitively inexpensive given that they are constructed using self-mixing Gunn-diode oscillators. Some make use of quadrature mixers for detecting the direction of movement. By counting the number of Doppler-periods and subtracting all periods with opposite signs, a pedestrain can be distinguished from swinging objects. So the frequency of false alarms can be reduced significantly.

- Simulation of High speed Particles encountered by space vehicles

The simulation of the movement of meteorites can be performed using light gas guns. The measurement of the velocities of these particles can be performed with a wave guide and an antenna, which is situated parallel to the trajectory of the particles inside a vacuum tank.

- Doppler-Radar used as Electric Rear-View Mirrors

An experimental model of an electronic rear-view mirror for cars using the Doppler-principle has been tested. A homodyne quadrature mixer produces a LF-signal. The signal that varies with speed and direction of travel, indicates vehicles passing from the rear of the vehicle. The antenna diagram has an opening of 8^o in the horizontal direction and only 5^o in the vertical direction. Using an inexpensive mechanical design with two 6 dB couplers for the mixer diodes, 100 mW transmitter power and a LF-bandwidth of 13 kHz (for a maximum speed difference of 200 km/h), a maximum range of around 150 m could be achieved.

- Measurement of length and speed of trains

The status of a track is an important check for railway systems. For this purpose a 35 GHz radar head, as used for traffic radar can be installed. The signal processing is fully digitalized and performs an autocorrelation analysis of the Doppler signal. Besides direction and speed, location of the beginning and the end of a train can be extracted, and the length of the train is determined. Also counting the number of cars or the recognition of a specific train configuration is possible.

b) With Modulation

- Collision Warning for Cars

To determine the safe distance to a preceding vehicle, various types of radars have been developed in different countries. In Germany two types using the FM-CW-principle and one using the pulse-principle have been developed and in Japan investigations are ongoing using optical systems. All the various systems utilize a computer, which calculates the safe minimum distance between vehicles using speed, speed difference, actual difference and deceleration values.

The FM-system at 35 GHz uses an FFT algorithm to extract distance and Doppler values of different targets. It has a distance resolution of 10 m, a distance accuracy of (+/-) 2.5-m, a relative speed measurement range of -30 km/h to +160 km/h, and a system reaction time of less than 0.1 sec. The primary problem, which has not been totally solved, is the false alarm rate. The false alarm rate is mainly caused by strong reflections from road side targets. Systems with angular resolution could be the answer to this problem in the future.

- Distance and speed measurement in Railway applications

A device similar in design to that used for automobile collision systems has been applied to measuring speed and distances of box cars in a railway shunting system. The system is used to automatically control the brakes on a track and is described in Reference 2.49. In this application, the environmental conditions are straighter forward because only one target is measured and the angular direction is given by the position of the track. The range of application is 10-m to 400-m.

- Precision measurement of Distance and Movement of machine parts in Strong Reflecting Environments

The movement of machine parts can typically be measured by optical means. In some cases, under conditions of heavy dust and clouds of water vapor, only microwave radiation can penetrate to the moving part. Also, if the machine parts to be measured are surrounded by other metal devices that also produce strong reflections, an “active” reflector which is LF-modulated can be extracted. This reflector consists of two horn antennas for perpendicular polarizations combined with diodes and a LF-oscillator. This arrangement is necessary because the distance to the part to be moved is impacted by the part’s rotation.

- Imaging of the surface of the filling of a Blast furnace

During steel production using a blast furnace, knowledge of the level of the materials contained within the furnace is useful in system analysis. Figure 2.10 depicts a Blast furnace filling surface imaging system. A profile of the level is measured in two directions using a frequency modulated carrier of 24 GHz with a periscope antenna located in a lance that can be raised or lowered as needed.

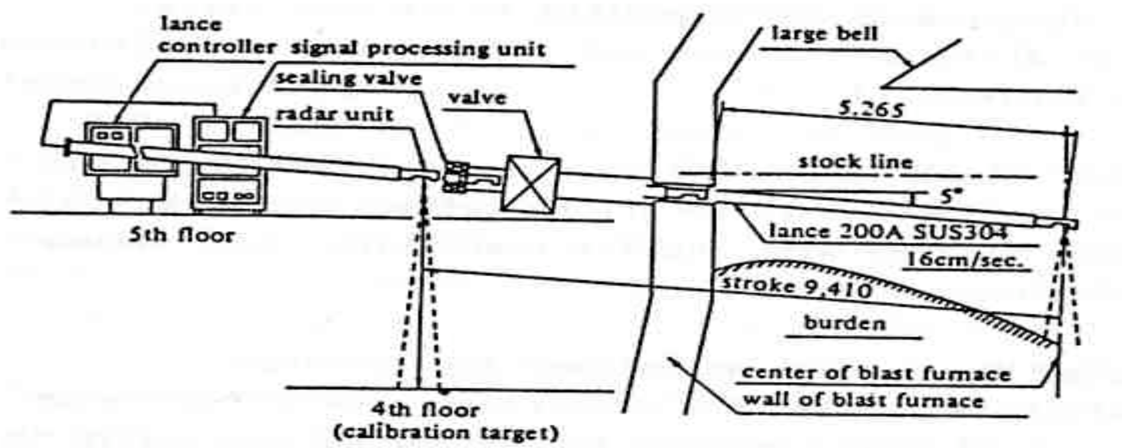

Fig. 2.10: *Blast furnace filling surface imaging systems*

- Precision Altimeter for ground impact warning of Helicopters

These altimeters by necessity are designed for very high accuracy. The systems are operated at 35 GHz. The FM-CW type has a transmitted power of 100 mW. The frequency sweep across a 1 GHz bandwidth is linearized by a digital control with a sweep lookup table of 4096 values. Two small wave guide horn antennas with only an 8 dB gain illuminate an angle of 90^o. This is necessary because of the variable altitude of a helicopter. The signal processing unit uses on line FFT analysis to evaluate the range profile from which the distance to surface is extracted. Instead of an optical display, a synthetic speech generator is used in place of an optical display and provides necessary information to the pilot. The maximum range is 200m and the low range resolution is 15cm.

2.5.3 Microwave Sintering

New developments and innovative ideas in the area of materials processing have often led to the discovery of new materials with interesting and useful properties, and new technologies which are much faster, better, cheaper and cleaner. Microwave sintering of ceramics is one of them. Among the most prominent advances in the past year were those reported on tungsten carbide (WC)-based ceramic composites, fabrication of transparent ceramics, sintering of powdered metals, and the design of a continuous microwave system to enable the commercialization of the technology. The vast majority of papers dealing with microwave heating of solids attribute the heating to energy loss mechanisms of the electric vector. Very recently, experimental findings have demonstrated that magnetic losses play an important role in microwave sintering of bulk materials for a wide range of conductor and semiconductor materials.

In 1999, the Pennsylvania State University's Materials Research Laboratory established experimentally that contrary to all previous practices and experiments that ordinary powdered metal samples or virtually any composition including very complex shaped and large (100 mm diameter and weighing approximately 2.2 pounds heavy) could be fully sintered in 30 minutes or less in a 2.45 GHz multi-mode microwave cavity. Moreover, the samples obtained had properties as good as, and in most instances, better than those sintered in conventional furnaces. This contradicted most of the earlier work which claimed that powdered metals could not be sintered by microwave energy. In 1994 Cherradi published a paper in which they showed that the magnetic field must make substantial contributions to the heating of alumina (at high temperature), semi-insulators, and metallic copper. In that work, their experimental design of using samples of 120 mm in length was such that the sample was always heated in both H and E fields simultaneously. The applicability of microwave sintering to metals had been ignored because most metals are known to reflect microwaves. The first publication of some of the preliminary results on microwave sintering of the powdered metals appeared recently from the same research group mentioned above from the Pennsylvania State University's Materials Research Laboratory.

2.5.3.1 Microwave Sintering Process

As previously indicated, Microwaves are electromagnetic radiation with wavelengths ranging from about 1 mm to 1m in free space and with frequencies ranging from 0.3 GHz to 300 GHz. However, only narrow frequency bands centered at 915 MHz and 2.45 GHz are used for research purposes. Microwave heating of materials is fundamentally different from conventional heating in that the heat is generated internally within the material instead of originating from an external heating source and subsequent radiative transfer. The heating is very rapid as the material is heated by energy conversion rather than by energy transfer, which occurs in conventional techniques. Microwave heating is a function of the material being processed and depends upon factors such as size, geometry and mass of the sample. In actual practice the sample becomes the source of heat during microwave processing.

Microwave processing has become significant in recent times for use in materials synthesis and sintering mainly because of its intrinsic advantages such as rapid heating rates, reduced processing times, substantial energy savings, novel and improved properties, finer microstructures and being environmentally cleaner. The Microwave Research Group at the Materials Research Institute of the Pennsylvania State University, first made the step function advance in the microwave sintering of many traditional and advanced ceramic materials, such as alumina, mullite and hydroxyapatite by demonstrating very rapid sintering in time intervals varying from 3-20 minutes. This led to transparency and improved density of the material. This same step function has been demonstrated in other commercial ceramics such as zirconia, zinc oxide, perovskites and silicon nitride. The use of microwave processing has been most fully developed in the laboratory mentioned above and elsewhere to cement carbide parts used in cutting and drilling tools. Ceramic processes where microwaves have been applied include process control, drying of ceramic sanitary wares, calcinations, decomposition of gaseous species by microwave plasma and sintering of oxide ceramics by microwave plasma. The interaction between microwaves and matter takes place through the electric field vector and magnetic field vector of the electromagnetic field of the microwaves and involves polarization and conduction processes. Classically, various absorption techniques have been identified in the interaction of microwaves with matter such as dipole reorientation and conduction of space and ionic charge, which are primarily found in insulators or dielectric materials.

In work with direct application to the oil industry, progress has been made in increasing the strength of drill bits using sintering process. This section will consider the other applications of microwave technology to the oil and gas industry.

2.5.4 Oil industry applications

Various engineering applications were previously discussed in detail. In this section microwave usage in the petroleum industry is considered. One such application is for use in flow measurement systems. Multi-component and multi-phase flow measurements where any combination of oil, water and air can occur are common to many industrial settings. Examples include the chemical and process industries, power plants, petroleum refineries and petroleum production facilties. The flowrates of crude oil, natural gas and water as a three-phase mixture in an oil well are the basic parameters in the oil production. The objective is to precisely and continuously measure the flowrates in order to control and predict the oil production. In general, natural gas and oil water are measured separately by using single phase flowmeters, such as a turbo meter, orifice plate, after heating and separating three-phase mixture into gas and liquid phases. Consequently, measuring equipment is complex and expensive. The variation of three-phase flow pattern, phase fraction and liquid viscosity with temperature makes it difficult to measure the multi-phase flowrate by using a single phase flowmeter. Additionally, the flow properties of oil/gas/water mixture are not known in detail and usually, gas and liquid flow in different velocity and regimes (patterns). Environmental influence on the measurement of phase fraction is also an important factor.

Accurate measurement of production fluids from the wells is essential for efficient management of reservoir and surface facilities of an oil field. During the last decade, significant progress in the development of MPFMs for online measurement of well production has been reported.

To measure the flowrate of multi phase, two techniques were tested [2.35] and compared using different operating principles. The first type of multi phase flow meters (MPFM), utilize a fluid container to separate the gas, which is measured by a vortex shedding flow meter. Liquid flow is measured with coriolis meter. The other MPFM employs a positive displacement meter, a venturimeter and *microwave* sensor to measure the flow of the total fluid, gas and water respectively. Beyond accurate measurement of production fluids from wells, subsystems to control fluids are required. The next section discusses the components used in a typical fluid control sub system.

Fluid Control Subsystem:

The fluid control subsystem consists of a fluid conditioner vessel (to separate the free gas from the oil-water liquid stream) and three different legs; the gas leg, the liquid leg, and the analysis leg:

- **Gas leg**

  The free gas separated from the inlet well fluid passes through a vortex shedding type gas flow meter (GFM) and the flow rate is recorded by the computer subsystem. The gas differential pressure valve (GDPV) continuously maintains a pre-selected value between the gas flow meter and the outlet of the MPFM.

- **Liquid leg**

  The liquid leg consists primarily of two mass flow meters (coriolis type) MM1 and MM2 in parallel. For wells with low production rate, there are provisions to isolate one of these meters. Use of only one meter improves the accuracy at low flow rates.

- **Analysis leg**

  A cylindrical chamber with instrumentation to measure the electrical characteristics (permittivity) of the oil-water mixture, differential pressure between top and bottom, and temperature and pressure form the analysis leg.

The results obtained were compared and the following conclusions were made from the tests described above. MPFM's using microwave measurements provide more accurate and more consistent results than conventional measurement systems. MPFM's were tested over a wide range of production rates (377 to 6661 bpd). Results are obtainable online and also well tests can be completed in a short time. A typical well test can be completed in 2 hours using manual switching of wells. Automated switchovers can enable well testing to be conducted in a shorter duration. Online monitoring of water cut and gas rate permits better management of high water cut and high gas producing wells (i.e. due to better understanding of the effect of choke size on water and gas production). Input of fluid properties, such as density or salinity is not required by the operator.

The measurement of crude oil/natural gas/water flow rates using microwave techniques is undergoing study at Xian Jiaatong University [2.29]. The individual flow rates of crude oil, natural gas and water three phase mixture were measured separately by using a single phase flowmeter. The microwave technique is used to measure the water to oil and gas ratios. It can measure 0-100% water concentration in water/oil two-phase mixtures and oil/gas/water three-phase mixtures. This instrument is not temperature or salinity sensitive and uses the capacitance cross correlation method to measure the overall flowrate of a three phase fluid. This type of three-phase flowmeter is suitable for many types of oil wells and measures the flowrates of crude oil, natural gas and water, including those with high water to oil ratios or high gas to oil ratios. The flowmeter is compact and non-invasive. It maintains high accuracy during measurement, despite the presence of paraffins, tar and sand. Its low cost makes it useful for installation on each oil well.

The microwave is also used in detecting devices used for the detection of water in crude oil and their application to royalty and custody transfer measurements [2.37]. This application is under investigation and addresses the need to comply to more stringent requirements of crude purchases. The dielectric constants and conductivity of water are much higher than that for oil. This difference can be utilized to measure the water content of oil/water mixtures. The water cut meter measures the microwave dielectric properties of mixtures using the resonant cavity method. The natural vibration frequency of a tube is affected by the density of a material in it. With the measurement of this frequency, density is also measured. This technique of water in crude detection is used in various oil field applications such as well testing, production operations and process flow. Experiments were conducted to test the meter’s accuracy and range of applicability.

When compared with the conventional crude oil sampling system, the conventional crude oil sampling systems are situated outside the pipeline. The only interface with the flowing liquid is via a thin sample probe device. The grab sample usually travels some distance to the sample container which creates fluid dead legs in the sample lines. The conventional sampling procedure is accomplished in several steps that consume time and require almost constant maintenance given the many parts making up the equipment. The water cut meter is installed in line and is in direct contact with the process fluid. The meter yields real time continuous water content in the crude line by measuring dielectric constants and conductivity of the water/crude interface. This meter is automatically temperature compensated and is designed to yield a minimum pressure drop during measurement. It is easily field calibrated for different process fluids and requires little maintenance. However, the water cut meter requires a line mixer upstream of the meter and does not quantify the sediment. Moreover, it may impact flow conditions since it, as previously mentioned, is installed in the flow path and in direct contact with process fluid.

Oil-Water treatment

Microwave radiation also has application to the treatment of waste-water/oil emulsions [2.38]. An emulsion is a polyphasic system consisting of two immiscible liquids where one of them is found as tiny drops suspended within the other. These emulsions are common to the petroleum industry and are formed as a mixture of crude oil residues, water, drilling mud and a variety of other agents.

Stability of emulsions is determined by the oil's aromatic content. Oils with high aromatic content have higher viscosity, which makes water separation more difficult. Most common kinds of instability of emulsions are flocculation, coalescence, inversion and sedimentation. Several factors that impact the breaking of an emulsion are water-oil ratio and drop diameter distribution. Microwave methods are able to destabilize water/oil emulsions and augment the separation of the water and oil by two means. First, by increasing temperature, the continuous phase viscosity is reduced and the outer film of drops broken. This permits coalescence. Second, the electrical charge distribution of the water molecules are rearranged while rotating them, and moving ions around the drops. The kinds of waste-water/oil emulsions depend upon the composition of the oil phase. For example lubricant paraffinic oil bases come from crude oils with high alkane content and have a sharp viscosity-temperature relationship. These actions combined result in the breaking of the emulsion without adding any chemical agents. The sample emulsions undergo a domestic microwave radiating process at several exposure times. Certain factors, such as aromatic components and sodium hydroxide content, emulsion mixing method and total heat exposure time proved to be the factors that strongly affect the results. By using the microwave radiation exposure, an aqueous phase recovery of 60-80% range is observed.

This idea to use microwaves in the treatment of oil field emulsions was first suggested in 1983 by Klaila and in 1986 by Wolf in their patent documents. Microwave heating proved to be an effective method for this purpose as it generates a uniform linear temperature profile in the horizontal direction, thus providing a faster water-oil separation. The results are given in the paper by Vega and Delgado. Presence of NaOH in the emulsion acts as a stabilizing factor. High viscosity lessens water recovery percentages since high viscosity increases the sedimentation time and delays the separation process. For high viscosity cases, mechanical agitation can be employed to reduce drop size and to standardize drop distribution. As a consequence, oil-water separation is enhanced and a linear temperature profile is promoted. The results were published in the paper mentioned above and indicated that microwaves impact the efficiency of the process by reducing the time duration attendant to emulsion breaking.

Remediation of areas contained by hydrocarbons using Microwaves:

An innovative process that removes hydrocarbon contamination from near surface formations and groundwater using microwaves will be discussed in this section. This technology is effective in increasing the recovery of light, non-aqueous phase liquid (NAPL) and its contaminants. Microwaves are generated in a trailer-mounted unit on the surface. These energy wares are transmitted through a conduit called a wave-guide. The waves travel though the wave-guide and are emitted from a sub-surface antenna suspended in a source well. The antenna is positioned at the water-hydrocarbon interface. The source well is surrounded by recovery wells.

Based on tests reported by Ferri and Uthe [2.41], heating is a small contributor to the mechanism attendant to hydrocarbon recovery rate. Microwave energy dissipates as a sphere around the antenna within the contaminated geologic zone. At a distance from the antenna, when the energy encounters a hydrocarbon molecule at the appropriate energy level, where energy is thus absorbed as a consequence of the energy absorption, the molecule gains internal energy and increases its internal motion. These mechanisms break the bonds between the hydrocarbon molecules and any contaminants and give the molecule the energy necessary for movement. With time, these molecules will migrate into the radius of influence at a recovery well and be produced to the surface.

Tests conducted at the Enhanced Recovery Inc. have shown that the volatile constituents are the first products recovered rendering the remaining hydrocarbons to be less toxic to humans and the environment. Further, recovery quantities and rates can be enhanced with the use of in-situ microwave energy. It was concluded that additional work is needed to further define the reaction between hydrocarbon and microwaves. Also, this technology reduced remediation costs compared to alternatives such as pump and treat systems by eliminating the contamination at the source with no further treatment.

Application of Microwaves to thermal improved oil recovery

Ovalles et al [2.27] reported case studies of the use of downhole dielectic heaters for improved oil recovery from reservoirs containing medium, heavy and extra-heavy crude oils. These reservoirs are located in Venezuela where the thermal improved oil recovery techniques are commonly used. Crucial to thermal IOR techniques is the process of downhole heating and the delivery of this heat energy to the required point in the reservoir. The experimental setup is shown on Figure 2.12

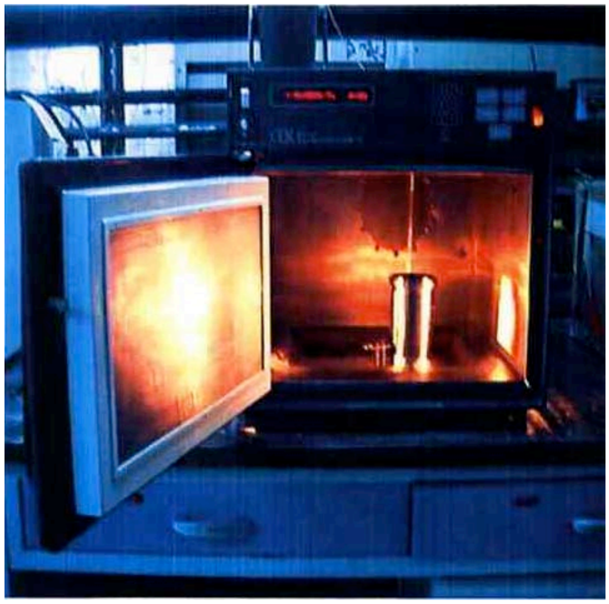

Fig. 2.12: *Experimental apparatus used for model validation*

Thermal IOR is predicated on the heating of formation fluids and porous media. This heating results in improved mobility of the oleic phase, relative to the aqueous and gas phase, with the concomitant increase in oil production. Generally, four different approaches have been reported in the literature such as Single and inter-well electromagnetic heating, resistive tubing heating and RF or MW dielectric heating. The advantages of RF or MW dielectric heating include higher penetration of the energy into the reservoir and compatibility for use in reservoirs that are shallow and thin. As previously indicate case studies were reported that provides insight into the field application of the heating process. Also the results of experimental studies of the technology were also reported physical model.

The laboratory apparatus included a CEM microwave oven, model SAM-155 with 650 W of power and a 1-D physical model. The experimental apparatus consists of a 300 ml cylindrical stainless steel reactor in which the top had been removed so that the electromagnetic energy penetrates downward. This vessel is placed in the microwave oven cavity and securely connected to ground to avoid electrical discharges. Typically, 70 g of medium (25^{o}API) or extra-heavy (7.7^{o}API) oil-containing sands were used and temperature profiles were measured with a four-point thermocouple. For studies with medium crude oil, temperatures were measured after heating durations of 0.5, 1.0 and 1.5 minutes. For the extra heavy oil the heating durations were 1, 5 and 10 minutes. Temperature readings were made after the application of MW energy was discontinued. The results of the temperature recordings were verified with optical sensors.

A mathematical model using the Lambert's equations was proposed.

$$\nabla^2 E(\vec{r}) + k^2 E(\vec{r}) = 0$$
$$k = \frac{\omega}{c}\sqrt{\varepsilon^*} \qquad \text{-------- (Eq 2.6.1)}$$

Where, the propagation constant, k, receives contributions from the electrical conductivity and permittivity through the complex dielectric constant $\varepsilon^*(\omega)$. To describe the absorption of the waves by the sample, two mathematical expressions can be considered, the Maxwell's and Lambert's equations. Maxwell's equation considers waves traveling in opposite directions, which include reflection effects at the interfaces that delimit the medium, as well as interface contributions that may cause resonance. By contrast, Lambert's law ignores all the effects that result from reflection at the interfaces. Both equations can be used to determine the dependence of the radiation power on the distance and are derived from the classic electromagnetic theory. A conceptualized reservoir model as illustrated in Figure 2.13 was formulated.

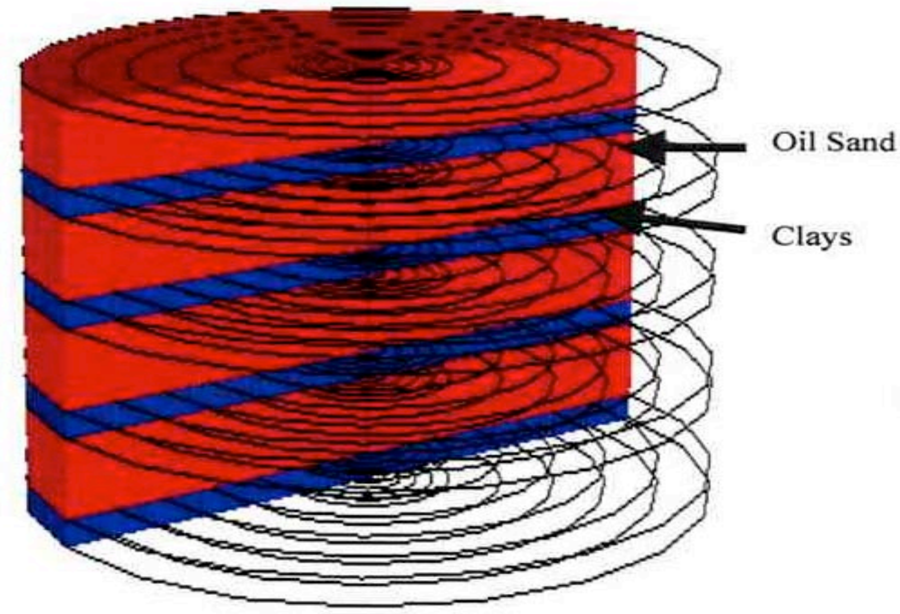

Fig. 2.13: *Lateral view of the conceptual reservoir used for the numerical simulation during dielectric heating of extra-heavy crude oil (7.7^o API)*

Using a one-dimensional MW (2.45 GHz) heated reactor, the model proposed was validated in the presence of a medium (24^{o}API) and extra-heavy crude (7.7^{o}API) crude oil/sand core with an average standard deviations of ±1.7^{o}C and ±4^{o}C, respectively. The numerical simulation of three different conceptual reservoirs containing medium, heavy and extra-heavy crude oils demonstrated an increase in the oil production due to RF and MW heating. This increase in production in was attributed to a reduction of crude viscosity. Energy gains ranging between 8 and 20 kW of incremental crude oil equivalent per kW of electricity for power sources as high as 100 kW were calculated. These results indicate that there is a potential for dielectric heating in reservoirs containing medium, heavy and extra-heavy crude oils as an IOR technology.

Application of Microwave energy to heat treatment of oil

Microwave energy can also be used in the heat treatment of heavy oil [2.28]. The problem to be addressed is that the viscosity of heavy oil needs to be reduced so that further treatment of it can be effected. Energy absorption varies depending upon microwave frequency, sample composition and temperature. Microwave energy can be used to selectively heat specific sites in a sample. For example an additive or catalyst mixed with heavy oil can be targeted such that the oil contacting the microwaves absorbing materials increases in temperature, while the bulk of the liquid remains substantially cooler. Two potential benefits of this technology are reduced coking of the crude and reduced energy input for hydrocarbon cracking. The rate of desulphurization and of cracking reactions could possibly be accelerated by using the microwave as the energy source.

Microwave heating is influenced by a number of parameters and the understanding of these parameters can influence where it has application. There are two important considerations – the design of the microwave oven and the dielectric properties of the materials being exposed to the microwaves. Data concerning the variations in dielectric property of material are given by Whanton et al [2.22]. The experimental set up used in these studies by Jackson did not include on apparatus to collect and measure gas generated in the heating of the crude oil tested. Measurement of the volume of the gas and its composition is required to perform a mass balance. It should be noted that only two frequencies within the microwave frequency range of 300 MHz to 300,000 MHz were considered. The treatment of heavy oil with additives resulted in different levels of upgrading depending upon the additives and the microwave frequency chosen. The best additive for this set of experiments is found to be activated carbon.

CHAPTER 2.6
FUTURE OUTLOOK

Microwaves and its application to various fields of study have been considered. This chapter considers possible avenues of future research.

2.6.1 Microwave imaging in medicine

This work is devoted to the development of microwave imaging techniques for biomedical applications [2.49]. The use of microwaves as a sensing device of living structures has been under investigation for a long time. Such devices were based on microwave penetration capabilities in biological tissues, as well as their sensitivity to tissue characteristics or movements. Initially Larsen and Jacobi developed a mechanical scanning system recording which permitted the of the complex transmission coefficient that is between two antennas located on both sides of the target under going a test. They were able to provide projection images of dog kidneys. These images exhibited unexpected quality in terms of spatial resolution and contrast. Indeed, the interaction of microwaves with highly contrasted structures is governed by diffraction laws. According to these laws it is not possible to produce very thin and well collimated microwave interrogation beams. The target is then widely illuminated and the measurement of the scattered field at a receiving antenna results from the contribution of the whole target. Furthermore, due to multiple scattering, the measured scattered field data are not linearly related to the dielectric constant of the target.

Accounting for the diffraction phenomena has been accomplished using two approaches. The first approach consists of neglecting the phenomena so that existing linear reconstruction algorithms developed for X-rays equipment can be used. The other approach takes into account the laws of diffraction. The basic equations relating the scattered field to target properties are inverted. Two main principles have been used, qualitative and quantitative imaging. Qualitative imaging consists of retrieving the so called equivalent currents, which are the currents included in the target by the microwave interrogation beam. Quantitative imaging consists of inverting diffraction equations, in order to retrieve the complex dielectric constant distribution in the target. Such an inverse problem is non-linear and is usually solved by means of iterative techniques.

Both spectral and spatial techniques can be compared in terms of spatial and time resolutions. For spatial resolution, the ultimate performance of spectral techniques imposed by well known diffraction limitations is of the order half the wavelength. Conversely, spatial iterative techniques permit high resolution, that is to say, spatial resolution better than diffraction limits, of the order of 10% or even 5% of wave length. Furthermore, the introduction of prior information, which is often available in clinical situations, has proven to result in a significant reduction in the computation time. In considering the application of the above discussed principle, microwave active imaging is a dielectric imaging process. To some extent, it can be compared to electrical impedance tomography which operates at much lower frequencies. The variations of the dielectric permittivity with frequency make microwaves capable of provinding different information and contrasts. The dielectric permittivity has been shown to be very sensitive to various physiological and physical parameters such as temperature, water content, and blood flow. Consequently, microwave images are expected to provide some information on the distribution of these parameters in biological targets. Microwave images should constitute a strong motivation for extensive dielectric characterization of living tissues, under normal and pathological conditions. Simultaneously, microwave imaging can be expected to provide, when accurate quantitative imaging equipment becomes available, a very attractive non-invasive characterization means.

As a matter of fact, non-invasive thermometry devoted to deep hyperthermia treatments has contributed to the development of research efforts in microwave active imaging. Besides hyperthermia, other applications have been considered corresponding to situations for which the dielectric constant is expected to be particularly sensitive to pathological diseases involving thermovasculary and water content changes. Inflammatory processes also provide a very large filed of investigations. The following aspects have been assessed within the frame of joint research programs with clinical units: the first one consists of the early diagnostic of fibrosis after therapeutic or accidental irradiation (Institute Curie, Paris); and the second concerns the follow up of renal transplants to detect rejection processes (Laboratory de Chirurgie Experimental). Another field application is the detection of metallic objects, such as endoscopic probes. Moreover, microwave imaging has been investigated as a possible means of controling the position of proton beams during protontherapy treatments of cancer tumors.

2.6.2 Adapting microwave techniques to help solve future energy problems

Electric power is such a desirable form of energy that its demand is expected to increase dramatically over time. The present methods of generating electrical power pollute the environment and consume natural resources such as coal and natural gas at a prodigious rate [2.4]. Previous research has suggested that new technologies, when coupled together can provide nearly continuous and pollution free electricity. Technologies such as the photovoltaic cell transform the sun's energy into electrical power. The placement of a solar photovoltaic cell in a orbit above the earth provide a duty cycle approaching 99-%. The efficient free space transmission of power is accomplished using a microwave beam. This latter technology allows the electrical power generated in space to be coupled to the earth with high efficiency using a wavelength of approximately 10 cm. At this wavelength, the normal atmospheric attenuation is about 2% becoming as great as 6% in torrential downpours.

Fig. 2.14: *Power Transmission from a space satellite using Microwaves*

Transferring power from a space satellite is an entirely new application for microwaves, which will challenge the microwave engineer with its technology requirements, while providing microwave engineering with an opportunity to contribute to man's quality of life. The various microwave technologies that are involved are: 1) the efficient conversion of dc power into microwave power; 2) the antenna technology of forming a narrow, efficient beam of microwaves and efficiently absorbing that beam on the earth's surface; and 3) the conversion of the microwave power back into dc power at the earth's surface.

The microwave system that is proposed for this application to handle huge amounts of electrically. Also, it is to be made up of components, which in power rating are well below the existing state of the art. The total power level of the free space power transmission system will need to be 10,000 megawatts and will require one or two million microwave generators. While the construction of these generators is sophisticated, the material and labor requirements do not differ greatly from those required for a similar quantity of microwave generators currently being projected for use in a year's production of electronic ovens. Another notable characteristic of the microwave systems is the method by which the microwave energy is captured and rectified at the earth's surface. This is accomplished by means of the rectenna device which is made up of a huge array of elements each consisting of a half-wave dipole terminated in an efficient rectifier of one or more Schottky-barrier diodes[2.3]. Such an arrangement allows the use of long-life diodes whose individual power handling capability is already adequate for the application. Even more important, this arrangement eliminates the high directivity characteristic of a conventional large antenna. Also, the characteristic of the beam is its high gains that are about 90dB. Such a high gain cannot be achieved without the use of self phasing principles which have been discussed in the literature. The application of these principles to the large array in space is primarily an engineering problem. Another characteristic of the beam is the very high overall efficiency that can be achieved, including the energy conversion process at both the transmitting and receiving ends. The efficiency of the beam to transfer microwave power is independent of distance if the aperture areas are increased in proportion to the distance of transmission; consequently, scaled laboratory experiments are applicable. A beam efficiency of 94% from the rf output of the microwave generator to the receiving aperture has been achieved. From these considerations and the knowledge that the efficiency of the rectenna can be greatly increased, an overall efficiency of 65-70% is projected for the microwave-power transmission system in the satellite solar power station concept.

Other important characteristic of the microwave power transfer system includes a minimal use of strategic materials, longevity and high reliability. A 20-30 year life time is projected for the system because of the use of long life semiconductors in the rectennas and the use of pure metal, secondary emitting (non-thermionic) cathodes in the microwave generators. The cost analysis to produce the microwave power transmission system inclusive of fabrication of the space transmitter and ground antenna, but exclusive of transportation into orbit and development cost have been made by William Brown. Because of the relatively small amount of material used, the relatively small number of different parts and the high automation made possible by long production runs of identical parts, the cost for 10,000 megawatt microwave power transmission system can be produced for less than $ 200.00 /KW. This will be a truly amazing technique to solve our future energy needs. The reference section gives the direction for some more details about these procedures[2.3].

2.6.3 Defense applications

According to Don Parker [2.1], the role of microwaves in the future defense applications will be of great importance. Microwaves and millimeter waves will enable the operation of military ground, surface, munitions, air, missile, and space-based radar and communication systems to become more integrated and interdependent. The future collector systems, processors and users use networks instead of autonomous platforms. During operations, the engagement systems will have the ability to reach back for information that will provide more adaptable quick-reaction forward footprints. The position of the soldiers will be known accurately with global positioning systems (GPS). The soldier will be able to access secure spread spectrum cellular like systems with voice and data links. Data from night-vision, spectrum-scanning and video sensors will be linked back to headquarter areas over cellular systems or directly to satellites. In addition to the improved radar and communication capabilities, this environment demands significant signal and processing capabilities. The processing speeds in excess of ten tera-operations per second will provide new oppurtunities for the microwave engineers. All these applications seem like a new dimension added to the present defense.

In any application, performance has been the overriding design criterion. The details about vacuum electronics (VE) and microelectromechanical systems (MEMS) were discussed by the author. It is also evident in his paper that monolithic microwave integrated circuits (MMICs) will be a dominant technology, but military requirements will demand the development of new materials and microwave devices (GaN and SiC) capable of providing lower noise and increased power, efficiency, band width and reliability in demanding thermal environments. Small ultra stable oscillators will be required to enable detection of small slow moving targets. Very low-loss and cost components for switching and phase shifting like MEMS will be required, especially for extremely large space based arrays and light weight uninhabited combat air vehicles. It is also felt that there will be higher levels of integration of microwave devices with mixed signal components for more compact and adaptable sensor front ends. Innovative packaging technology and integration techniques will be required to meet performance, volume, weight and cost constraints. Microwave components mounted on flexible substrates could satisfy these needs, as well as those of satellite systems that must be stowed for launch and deployed in space. If the future is multifunction arrays and ubiquitous radar, the signal processing functions will be moved forward to the high-PA and low noise amplifier at each element of the array and beam forming performed digitally. Such systems will require development of advanced adaptable direct digital synthesizers (DDS) and analog-to-digital converters that work at giga samples per second with high resolution and low power dissipation.

By considering all these, the author feels that multidiscipline experience in RF, mixed signal devices, photonics, and packaging technologies are of importance. The technical challenges that are offered by future microwave and millimeter-wave defense systems will attract experts to address the unique design and manufacturing problems.

2.6.4 Analog/Digital microwave considerations for Electric/gas utilities

Electric/gas utilities have been concerned with the issues related to the replacement of existing, aging, analog bulk communication systems which represent large investments. The older analog systems are primarily powerline carrier and microwave systems, where the newer ones are microwave and fiber optic systems. The issue is whether to replace the existing older analog systems with new analog microwave and fiber optic systems or with newer technology utilizing digital modulation techniques. In the recent pasts the obsolete analog microwave replacement cost estimates have been much greater using digital microwave than using new analog microwave equipment. The reason for this is that both the R. F. and multiplex equipment had to be replaced if digital microwave were used, whereas only the R. F. equipment need to be replaced if analog microwave were used. This paper [2.5] is a review of many technical papers on the subject of Analog/Digital microwave considerations and References 1-5 contain detailed information for those interested in exploring the subject.

For over three decades Electric/gas utilities have depended primarily on analog transmission media to implement the microwave networks essential to the reliable, economical operation of electrical power main grid and interstate pipeline systems. Presently analog telecommunication systems present few problems for transfer trip protective relaying purposes. In general the higher the bandwidth of the signal channel transmission medium, the faster the trip signal can be transmitted. Also, there are no timing problems for voice or data requirements. One of the worst problems for analog telecommunication systems is the lower data rates available for data processing equipment. Most medium capacity inter-city utility microwave applications make use of

6 or 7 GHz band. Either 9.75 MHz or 19.5 MHz channel allocations are available in this band. As these capacities do not conveniently match any of the standard rates, a combination of multiplexing and spectrally efficient modulation must be used to produce a practical product. It appears that the task of the microwave manufacturer is to optimize the cost and performance of any digital microwave offering. The additional transmission capacities provided by higher efficiency modulation techniques must be traded off against overall product cost and reduce signal robustness. For practical applications, both low and high efficiency products will be examined for the 6/7 GHz band.

In future the product remains available as long as the market remains. However, the availability of high-density analog radios is questionable as the electric utilities are a fraction of the microwave radio/fiber-optic communications market. Whereas the ease and low cost of base band traffic transfer to/from a spur is beneficial to the utilities, it is unimportant to the long-haul common carriers and corporate networks that are the telecommunications major market. To serve these needs most effectively, the high-speed data rate capability and noise immunity of digital transmission are preferred. Data rates due to evolving high-speed networks will require bandwidths far in excess of even digital microwave capacity. Fiber-optic communications, although a costly initial investment, becomes the most economical alternative as the data bandwidth requirements increase.

2.6.5 Microwave instruments development in European Space Agency's Earth observation future programs

This article[2.8] provides an overview of the microwave instruments currently in development under the future programs of the ESA's earth observation envelop program. They are structured accordingly and depend upon whether the technologies are used as an earth explorer or an earth watch candidate. The following section will discuss about some of the missions currently under development in ESA. The Earth explorer missions include:

1) EarthCARE is an earth explorer core candidate mission, proposed as a cooperative mission between ESA and NASDA, including the communication research laboratory (CRL) for the provision of the cloud profiling radar. A critical point of the radar is the extended interaction klystron (EIK) amplifier from CPI Canada that is used to generate a high transmit-power exceeding 1.5 KW.

2) ACECHEM is the atmospheric chemistry earth explorer core candidate that was not recommended initially. The principal and most innovative objective is to simulate the capability of MASTER, a millimeter –wave limb sounder payload of ACECHEM, for sounding O_3, H_2O and CO at high vertical resolution in the upper troposphere/lower stratosphere at bands around 300, 325 and 345 GHz.

3) ACE+ is a satellite constellation carrying GPS/Galileo occultation receivers and LEO-to-LEO occultation instruments for atmospheric profiling. The later requires extremely stable inter-satellite measurements (amplitude and phase) with high sensitivity during an occultation and presents interesting challenges for the transmitter/receiver development as well as for their characterizations.

The earth watch candidate missions include:

1) Post-EPS Meteorological instruments: in the context of future LEO meteorological satellites, a new generation of microwave atmospheric sounder and imagers as well as scatterometer are under consideration. The future sounder and imager shall provide better spatial and temporal resolution, better coverage and higher radiometric quality than the current instruments on board the upcoming EPS satellites.

2) Post MSG Microwave Sounder/Imager: millimeter and sub-mm-wave imager/sounder are considered for future meteorological and climate observation satellites. These instruments are desirable for the observation of rapidly evolving meteorological phenomena such as convective systems, precipitation and cloud patterns, providing the required high temporal resolution from a geo-stationary or medium earth orbit. The main emphases in all concepts are the observation of precipitation, ice clouds, atmospheric motion vectors and temperature and humidity sounding.

3) Future Altimeters: a new radar altimeter concept to provide high-resolution measurements of ocean and sea-ice topography is under study in the context of future

operational oceanography. It shall enable reliable measurements on coastal water as well as over sea-ice.

The future application of microwaves to the oil and gas industry appears to be focused on improved flow measurement systems. Also, with improvements in the transmission capabilities of microwave down hole, it has potential applications as a means of recovering heavy oil. Moreover, it has application to the transmission of data and for use in the monitoring/control of remote operations.

Summary

Microwave Engineering has been discussed in detail including its applications in various fields of Engineering. The applications are concentrated towards oil industry in particular. This report is a collection of work done by many research institutes, some of which are provided in the bibliography section. Please contact the authors for further information about any specific topic or research material. This report also includes a tutorial for providing some fundamental knowledge about the working of a home microwave oven in a CD attached.

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APPENDIX C

A C O U S T I C S

ABSTRACT

A literature survey to investigate the potential for the use of acoustic technology to advance oil and natural gas technology has been completed. Literature from the oil and gas industry and from geophysics publications was reviewed.

A comprehensive review of the literature was conducted previously by Beresnev and Johnson (1994) [3.1] and a summary of this work is provided. The authors concluded that natural seismic phenomena significantly altered the production of oil and water from numerous fields. Also, laboratory data indicating that acoustic stimulation increased the rock matrix permeability to hydrocarbons. Two applications of acoustic stimulation in the field were reported. The first is the use of an acoustic source to remove scales, muds, and other contaminants. This method was reported to be successful in 40%-50% of the cases in which it was applied. The second is a relatively new technology where surface vibrators are used to stimulate a large area of the reservoir. This method was applied in the former USSR and some success was reported.

It was recognized in the mid 1960's that acoustic technology has potential for application to various segments of petroleum recovery. Campbell and Duhon[3.2] reported encouraging results on the increase of oil recovery in controlled laboratory experiments where ultrasonic treatment was utilized. Direct use of ultrasonic energy to improve recovery was also reported. Campbell et al. demonstrated that a significant increase in simulated oil production during water flooding of sandstone and limestone cores was realized when ultrasonic energy. Experimental work by Roberts et al.[3.10] showed a definite increase in permeability of contaminated cores. These Brine saturated Berea sandstone cores were contaminated with fines and mud separately. Four-fold increase in permeability was reported, a result of significant importance since drastic decreases in permeability are caused by contamination of the near-wellbore region. Also Roberts et al. investigated the removal of paraffin and polymers from damaged Berea sandstone cores[3.12]. The ultrasonic treatment was successful

in the removal of paraffin but only marginal success was achieved in polymer removal. Another interesting set of results was reported on the use of ultrasonic treatment to remove asphaltene during oil production. Gllapudi et al. [3.11] reported a significant increase in permeability of sand packs subsequent to ultrasonic irradiation.

Other applications of ultrasonic technology include its use in data acquisition, reservoir characterization and metering. Ondrik et al.[3] reported the use of a borehole flow meter for production logging of a shale gas reservoir. Use of ultrasonic devices in drilling and completed has also been reported. Clerke and Van Akkeren utilized a borehole Televiewer to improve completion of infill wells. They showed that this device generated superior data to some conventional logs (gamma-ray, sonic, laterolog, and spherically focused) [3.4]. The authors demonstrated that ultrasonic devices can provide drilling engineers with information needed to improve oil recovery as accurate data can be acquired. The use of an ultrasonic flow meter for kick and loss detection during drilling was reported by Orban et al.[3.5]. The flow meter was capable of metering changes in mud circulation as low as 50 GPM, a range considered to be sufficient for indicating that a blowout is taking place. Other techniques for the measurement of important parameters in reservoir characterization were also reported[3.6, 3.7]. Hoyos et al. reported on a laboratory method for the detection of gas nucleation during primary depletion. Also, Soucemarianadin et al. devised a new method for saturation mapping of porous media.

Use of ultrasonic technology for well logging and interference testing was reported as well. Nayhavn et al.[3.8, 3.9]reported laboratory and field test results generated by an ultrasonic Doppler velocity probe designed for production logging of horizontal and deviated wells. The instrument incorporated the latest technology, at the time, in data filtering and presentation. The probe was used successfully to detect laminar, turbulent and gas flow respectively. Also use of ultrasonics in surface and bottom hole experiments to determine interference of wells was reported by Laird et al.[3.9]. The apparatus incorporated an EOS-based model for pressure determination from data acquired by the use of surface and bottom hole sensors. Also, newly developed temperature compensation technology was utilized. Equipped with this new tool, the investigators were able to determine that the geological mapping of the field was incorrect and suggested new interpretations that could lead to improved recovery.

It is concluded that there is a need for the development of a theoretical/mechanistic framework that explains reported laboratory and field results in the area of acoustic stimulation. Another important observation is that the experimental and field results need to be examined more carefully in order to explain some of the discrepancies among the results. Also, future work needs to be focused on the circumstances under which favorable results are obtained. This will aid in designing and conducting the experimental work needed to demonstrate the mechanisms that take place subsequent to or concurrent with acoustic treatment. The next step is to scale up the laboratory experiments to pilot test and then to design industrial scale stimulation units.

LIST OF FIGURES

CHAPTER 3.1

INTRODUCTION

Acoustics in simple words can be defined as the science of sound. It also includes production of sound, its transmission, and also the effects caused due to the sound production. As opposed to the older scientific belief, in present usage, the term sound implies not only phenomena in air responsible for the sensation of hearing but also whatever else is governed by its analogous physical principles. Thus, any disturbances caused, be they with frequencies too low (infrasound) or too high (ultrasound) to be heard by a normal person are also regarded as sound. One may speak of underwater sound, sound in solids, or structure-borne sound. Acoustics is distinguished from optics in that sound is a mechanical, rather than an electromagnetic, wave motion. Acoustic energy results from the transformation of mechanical energy to sonic or ultrasonic waves. Acoustic waves only propagate through media, which are elastic. The propagation of such a wave provokes oscillation of the elements of the medium. The oscillation amplitude decreases until the elements revert to their equilibrium state. Acoustics can be regarded as a matter of communication. Taking account of music, speech, listening spaces or hearing, signaling or ultrasonic we seek to maximize the tendency to convey information and minimize the effects of noise.

The broad scope of acoustics as an area of interest and endeavor can be ascribed to a variety of reasons. First, there is the ubiquitous nature of mechanical radiation, generated by natural causes and by human activity. Then, there is the existence of the sensation of hearing, of the human vocal ability, of communication via sound, along with the variety of psychological influences sound has on those who hear it. Such areas as speech, music, sound recording and reproduction, telephony, sound reinforcement, audiology, architectural acoustics, and noise control have strong association with the sensation of hearing. That sound is a means of transmitting information, irrespective of our natural ability to hear, is also a significant factor, especially in underwater acoustics. A variety of applications, in basic research and in technology, exploit the fact that the transmission of sound is affected by, and consequently gives information concerning, the medium through which it passes and intervening bodies and inhomogeneities. The physical effects of sound on substances and bodies with which it interacts present other areas of concern and of technical application. Traditionally, acoustics has formed one of the fundamental branches of physics. One can stumble upon acoustic specialists not only in the physics department but also in mechanical & electrical, mathematics, oceanography programs. Applications span from musical instruments to curing of speech related problems.

Some indication of the scope of acoustics and of the disciplines with which it is associated can be found in Fig, 3.1. The first annular ring depicts the traditional subdivisions of acoustics, and the outer ring names technical and artistic fields to which acoustics may be applied. The chart is not intended to be complete, nor should any rigid interpretation be placed on the depicted proximity of any subdivision to a technical field.

(A detailed listing of acoustical topics can be found in the index classification scheme reprinted with the index of each volume of the *Journal of the Acoustical Society of America*.)

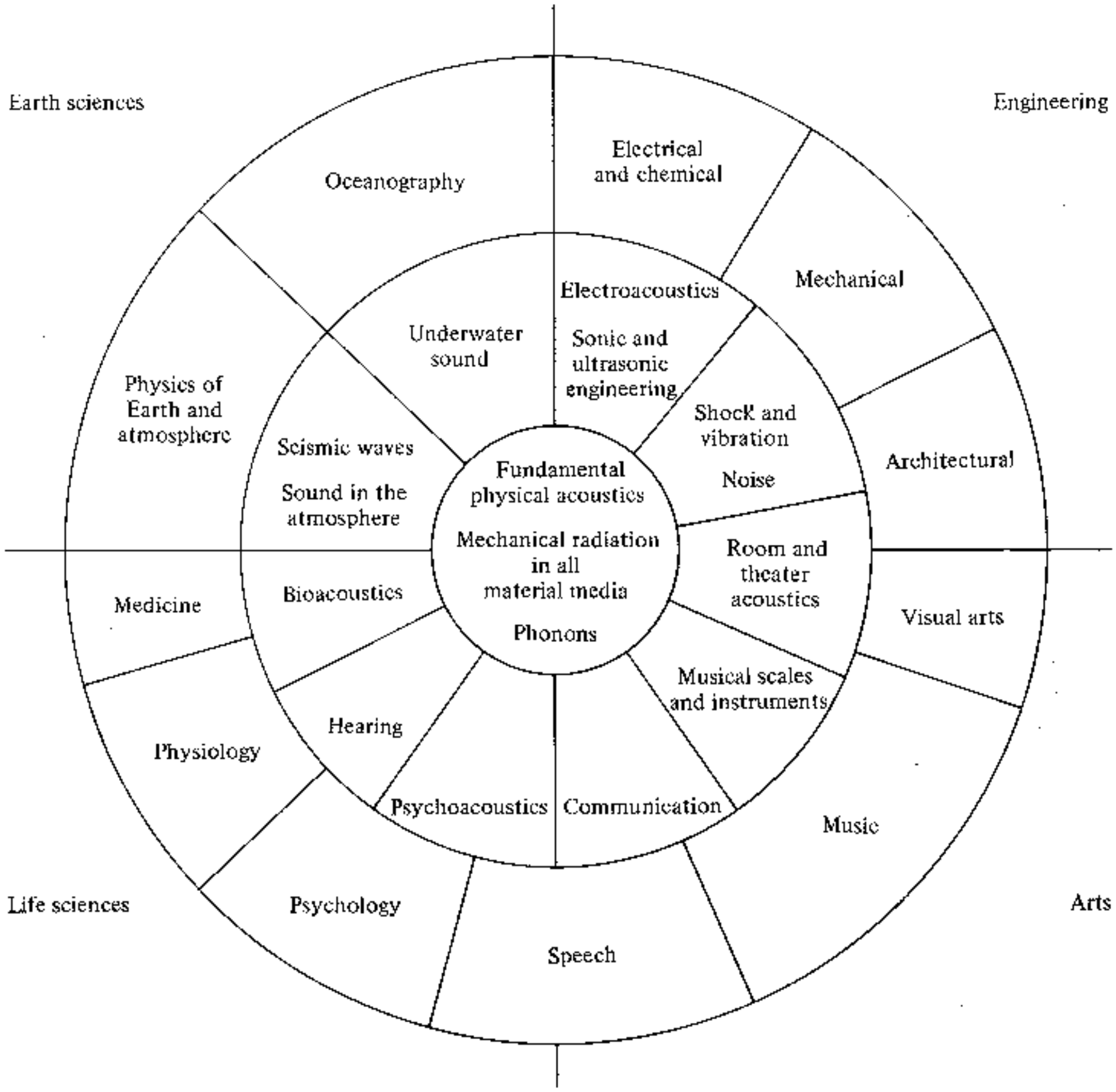

Fig. 3.1: *Circular chart illustrating the scope and ramifications of acoustics. Courtesy R.B. Lindsay, J. Acoust. Soc. Am. 36:2242 (1964)*

CHAPTER 3.2
HISTORY

With sound as a major factor affecting human lives, it was apparent for the acoustics – the science of sound, to emerge. Lin-lun, a 27th century BCE minister of emperor Hagundi was commissioned to establish a standard pitch for music. He took the task of casting 12 standard pitch pipes, to enable composing of music. This gave further interest to involve oneself in the mechanism of sound and how it was really produced. The speculation that 'sound is a wave' grew out of observations of water waves. The ancient Greeks surmised that sound is an oscillating perturbation emanating from a source. The rudimentary notion of a wave is an oscillatory disturbance that moves away from some source and transports no discernible amount of matter over large distances of propagation. Among the early acousticians who proposed the possibility that sound exhibits analogous behavior was the Greek philosopher Chrysippus (c. 240 B.C.), the Roman architect-engineer Vetruvius (c. 25 B.C.), and the Roman philosopher Boethius (A.D. 480-524). The wave interpretation was also consistent with Aristotle's (384-322 B.C.) statement to the effect that air motion is generated by a source, "thrusting forward in like manner the adjoining air, to that the sound travels unaltered in quality as far as the disturbance of the air manages to reach."

A pertinent experimental result inferred with reasonable conclusiveness by the early seventeenth century, with antecedents dating back to Pythagoras (c. 550 B.C.) and perhaps further, is that the air motion generated by a vibrating body sounding a single musical note is also vibratory and of the same frequency as the body. The history of this is intertwined with the development of the laws for the natural frequencies of vibrating strings and of the physical interpretation of musical consonances. Principal roles were played by Marin Mersenne (1588-1648), a French natural philosopher often referred to as the "father of acoustics," and by Galileo Galilei (1564-1642) who's Mathematical Discourses Concerning Two New Sciences (1638) contained the most lucid statement and discussion of frequency equivalence.

Mersenne's description in his Harmonic Universelle (1636) of the first absolute determination of the frequency of an audible tone (at 84 Hz) implies that he already demonstrated that the absolute-frequency ratio of two vibrating strings, radiating a musical tone and its octave, is as 1:2. The perceived harmony (consonance) of two such notes would be explained if the ratio of the air oscillation frequencies is also 1:2, which in turn is consistent with the source-air-motion-frequency-equivalence hypothesis.

The analogy with water waves was strengthened by the belief that air motion associated with musical sounds is oscillatory and by the observation that sound travels with a finite speed. Another matter of common knowledge was that sound bends around corners, which suggested diffraction, a phenomenon often observed in water waves. Also, Robert Boyle's (1640) classic experiment on the sound radiation by a ticking watch in a partially evacuated glass vessel provided evidence that air is necessary, either for the production or transmission of sound.

The wave viewpoint was not unanimous, however. Gassendi (a contemporary of Mersenne and Galileo), for example, argued that sound is due to a stream of "atoms" emitted by the sounding body; velocity of sound is the speed of atoms; frequency is number emitted per unit time. It was Joseph Sauveur (1653-1713) who suggested the term acoustics, which emanated from the Greek word for sound

The apparent conflict between ray and wave theories played a major role in the history of the sister science optics, but the theory of sound developed almost from its beginning as a wave theory. When ray concepts were used to explain acoustic phenomena, as was done, for example, by Reynolds and Rayleigh, in the nineteenth century, they were regarded, either implicitly or explicitly, as mathematical approximations to a then well-developed wave theory; the successful incorporation of geometrical optics into a more comprehensive wave theory had demonstrated that viable approximate models of complicated wave phenomena could be expressed in terms of ray concepts. This recognition has strongly influenced twentieth-century developments in architectural acoustics, underwater acoustics, and noise control.

With the beginning of the 18th century, scientists apparently started working on the theoretical physics and applied mechanics. The mathematical theory of sound propagation began with Isaac Newton (1642-1727), whose Principia (1686) included a mechanical interpretation of sound as being "pressure" pulses transmitted through neighboring fluid particles. The mathematical analysis was limited to waves of constant frequency, employed a number of circuitous devices and approximations, and suffered from an incomplete definition of terminology and concepts. It was universally acknowledged by his successors as difficult to decipher, but, once deciphered, it is recognizable as a development consistent with more modern treatments. Some textbook writers, perhaps for pedagogical reasons, stress that Newton's one quantitative result that could then be compared with experiment, i.e., the speed of sound, was too low by about 16 percent. Newton failed to realize that the prevalent mode of acoustic vibrations was isentropic, not isothermal as he had assumed. Separate experiments by Count Giovanni Lodovico Bianoni (1717-1781) and Charles Marie de la Condamine (1701-1773) proved that temperature had a far noticeable influence on the sound of speed. Richard Helsham (1680-1758) developed the exponential horn.

Substantial progress toward the development of a viable theory of sound propagation resting on firmer mathematical and physical concepts was made during the eighteenth century by Euler (1707-1783), Lagrange (1736-1813), and Jean le Ronde d'Alembert (1717-1783). During this era, continuum physics, or field theory, began to receive a definite mathematical structure. The wave equation emerged in a number of contexts, including the propagation of sound in air. The theory ultimately proposed for sound in the eighteenth century was incomplete from many standpoints, but modern theories of today can be regarded for the most part as refinements of that developed by Euler and his contemporaries.

CHAPTER 3.3
PHYSICS

As we have already learned that acoustics is nothing but the science of sound and that very simply sound may be defined as the product of vibration of any substance, a thorough knowledge of the two aspects – **sound** and **vibration**, must be gained. As we proceed with each aspect, we shall discuss its underlying physics to obtain a better idea of the concept.

3.3.1 Sound

From a materialistic point of view sound can be perceived to be quickly varying pressure wave within a medium. By sound we usually refer to audible sound, which is the sensation detected by the ear of very small rapid changes in the air pressure above and below a static value. The 'Static value' is atmospheric pressure which is about 100,000 Pascal. Sound is a waveform that travels through matter. Although we generally associate sound waves in air, it can readily travel through many materials such as water and steel. On the other hand there are available insulating materials that absorb much of the sound waves, preventing the waves from penetrating the material. Also note that light and radio waves are electromagnetic waves and are completely different from sound waves. Electromagnetic waves are related to electrical and magnetic fields and readily travel through space which sound waves cannot since they require an elastic medium for their propagation. Coupled with the sound pressure wave is a flow of energy. Diagrammatically, sound is often represented as a sine wave, but in reality it is a longitudinal wave where the motion of the wave is in the direction of the movement of energy. The wave 'crests' are the pressure maxima while the 'troughs' are the pressure minima.

A general range for sound to be potentially audible is when the rapid variations in pressure occur between about 20 and 20,000 times/second, i.e., frequency between 20Hz and 20 kHz. Pressure variation can sometimes be as low as only a few millionths of a Pascal. Louder sounds are created by greater variations in pressure. For example, a reading of 1 Pascal will sound quite loud, provided that most of the acoustic energy is in the mid-frequencies (1 kHz – 4 kHz) where the ear is most sensitive.

Sound is caused when the air is disturbed in some way, for example by a vibrating object. That mechanical disturbance is sound. If we consider a speaker cone from a music system to serve as a object that experiences vibration, as it is possible to see the movement of a bass speaker cone. As the cone moves forward the air immediately in front is compressed causing a slight increase in air pressure, a phenomenon called condensation. It then moves back past its rest position and causes a reduction in the air pressure, a phenomena called rarefaction. The process continues so that a wave of alternating high and low pressure is radiated away from the speaker cone at the speed of sound. When these substances vibrate, or rapidly move back and forth, they produce sound. This succession of moving rarefactions and compressions constitute a wave motion. However, we must realize that the vibrations that produce sound are not the result of an entire volume moving back and forth at once. The vibrations occur among the individual molecules of the substance, and the vibrations move through the substance in sound waves. As sound waves travel through the material, each molecule hits another and returns to its original position. The result is that regions of the medium become alternately denser, when they are called condensations, and less dense, when they are called rarefactions. Given below is an illustration of a Compression wave.

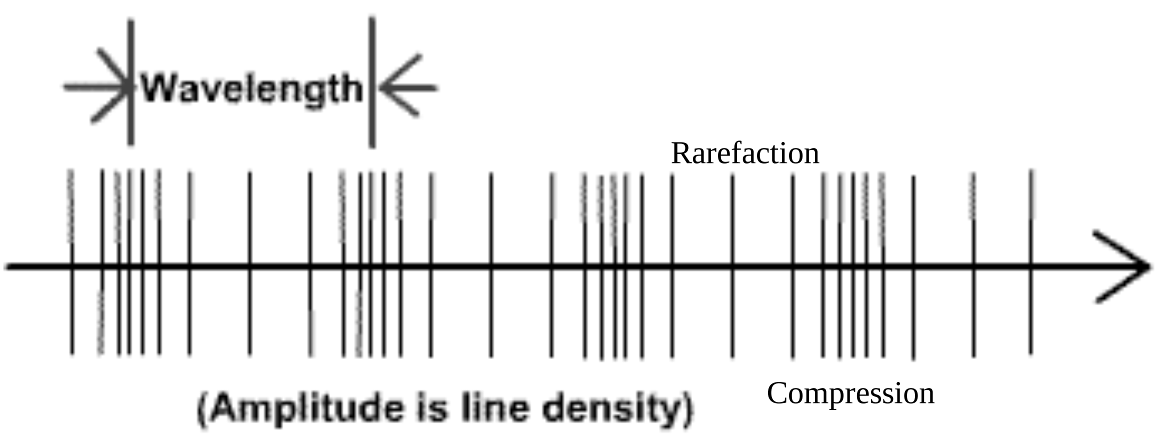

Fig. 3.2: *Compression Wave (sound wave)*

An analogous sine wave structure (transverse wave) can be illustrated as shown below. For easier understanding through this report, sound waves may be depicted in the form of transverse waves.

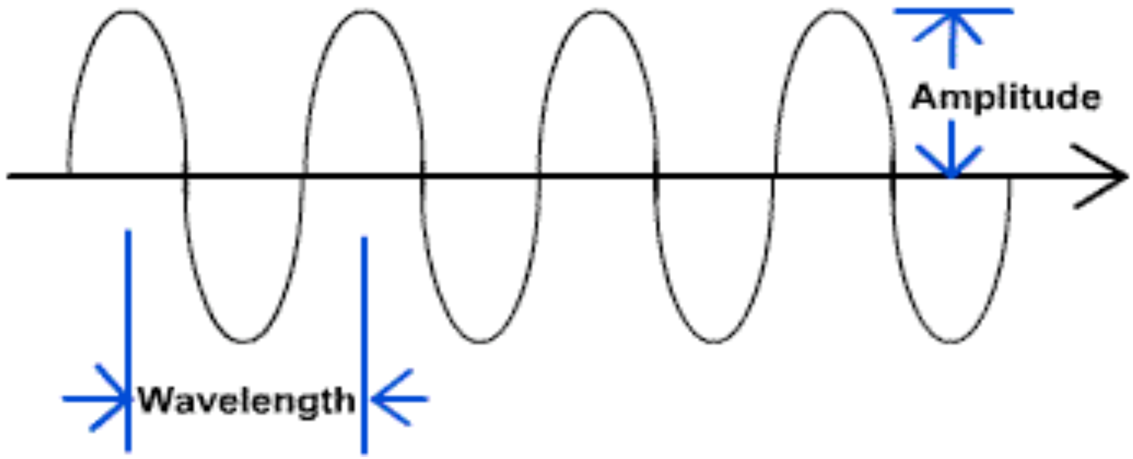

Fig. 3.3: *Transverse Wave (water wave)*

Like any other waveform sound waves also have characteristics like amplitude, velocity, frequency and wavelength.

Amplitude in a sound wave corresponds to the loudness. It indicates how much a wave can be or is compressed. Physically, amplitude is as indicated in the illustration above.

The *speed* of sound is actually the speed of transmission of a small disturbance through a medium. Disturbances are transmitted through a gas as a result of collisions between the randomly moving molecules in the gas. Because the speed of transmission depends on molecular collisions, the speed of sound depends on the state of the gas, i.e., the type of the medium and the temperature of the medium. The speed or velocity of sound in air is approximately 344 meters/second, 1130 feet/sec. or 770 miles per hour at room temperature of 20^{o}C (70^{o}F). The speed varies with the temperature of air, such that sound travels slower at higher altitudes or on cold days. A small section related to speed of sound is given in the following few paragraphs.

The *frequency* of sound is the rate at which the sound waves pass through a particular point. It also represents the so called the pitch of a sound.

Wavelength is the distance from one crest to another of a wave. Since sound is a compression wave, the wavelength is the distance between maximum compressions. This can be observed in the illustration above.

Since the human ear can perceive sounds which cover a large range of intensities, sound is measured in logarithmic units of decibels. The decibel in all cases is used to compare some quantity with some reference value. Usually the smallest likely value of the quantity is declared the reference value. Sometimes it can be an approximate value or maybe even an average value. In acoustics the decibel is most often used to compare sound pressure, in air, with a reference pressure. References for sound intensity, sound power and sound pressure in water are among others which are also commonly in use.

Reference sound pressure (in air)	= 0.00002 = 2E-5 Pa (rms)
Reference sound pressure (water)	= 0.000001 = 1E-6 Pa
Reference sound intensity	= 0.000000000001 = 1E-12 W/m^2
Reference sound power	= 0.000000000001 = 1E-12 W

Acousticians use the dB scale for the following reasons:

1) Quantities of interest often exhibit such huge ranges of variation that a dB scale is more convenient than a linear scale.

2) The human ear interprets loudness on a scale much closer to a logarithmic scale than a linear scale. Humans judge the relative loudness of two sounds by the ratio of their intensities, a logarithmic behavior.

The primary instrument for the measurement of general noise is the sound level meter. The indication on a sound level meter indicates the sound pressure as a level referenced to 0.00002 Pa.

Sound Pressure Level (SPL) = 20 x lg (p/0.00002) dB
where p is the sound pressure.

What might be the resulting effect of multiple sounds? If for example there are two sound sources in a room - a radio producing an average sound level of 62.0 dB, and a television producing a sound level of 73.0 dB - then the total sound level is a logarithmic sum, which is:

Combined sound level = 10 x log (10^ (62/10) + 10^ (73/10))
= 73.3 dB

For two different sounds, the combined level cannot be more than 3 dB above the higher of the two sound levels. However, if the sounds are phase related there can be up to a 6dB increase in SPL.

For a case when both the sounds have the same wavelength and are equidistant from the sound receiver the condensations of the wave coming from one speaker are always meeting the condensations from the other at the same time and so do the rarefactions. The addition causes an increase in the amplitude resulting in a louder sound. Under these conditions the waves are said to be exactly in phase and exhibiting ‘constructive interference’.

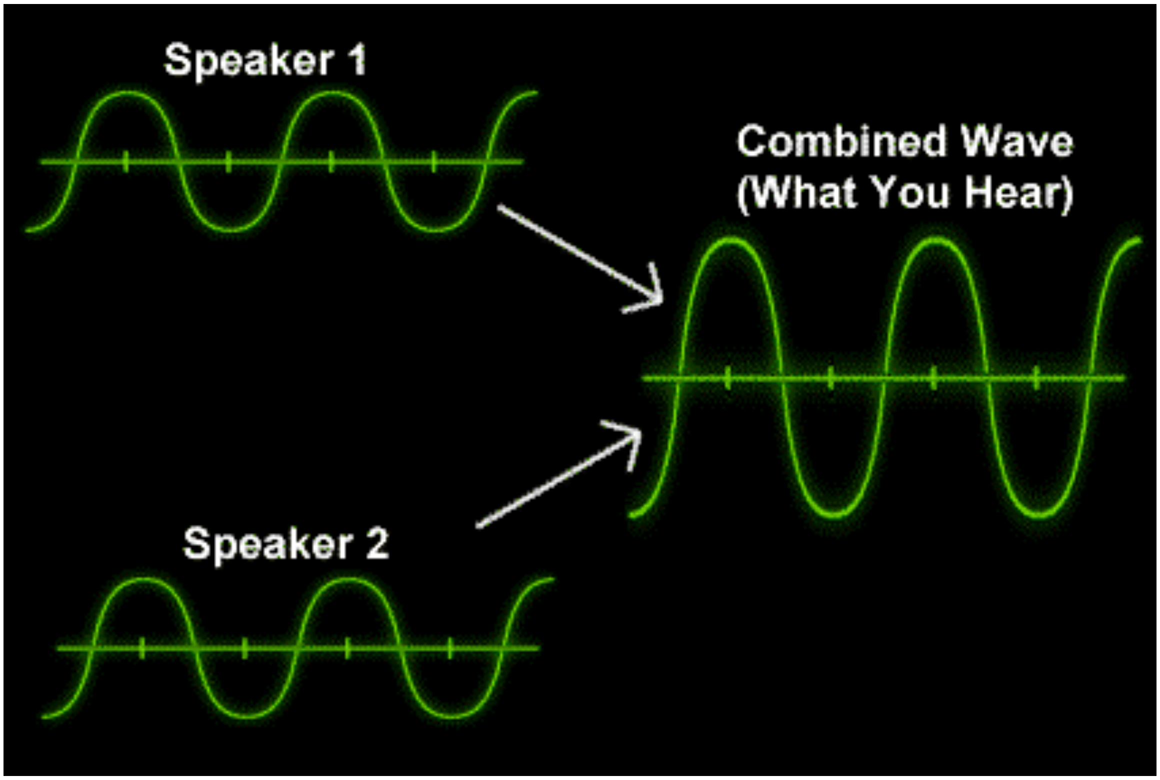

Fig. 3.4: *Constructive interference*

If the situation is changed such that the amplitude remains the same but the condensations from one speaker to meet the rarefactions from the other sound wave and vice versa. This will result in a constant air pressure which means that you can hear no sound coming from the speakers. This is called "destructive interference" where two waves are "exactly out of phase".

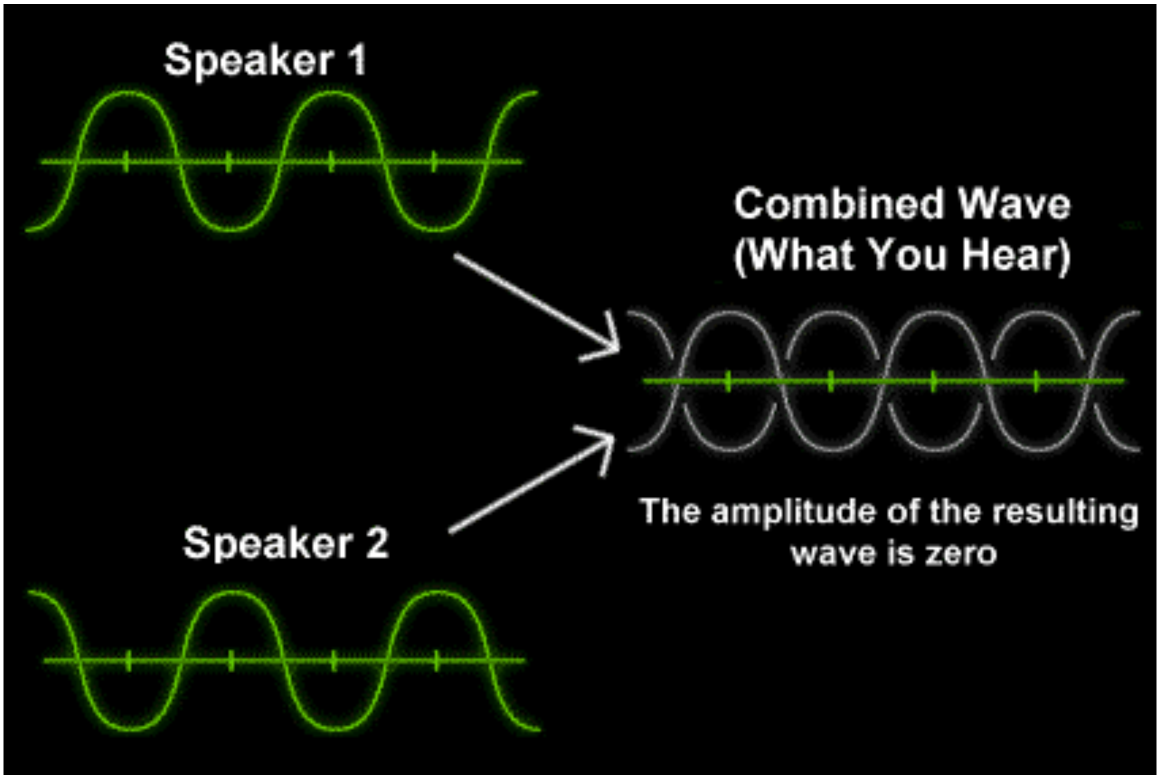

Fig. 3.5: *Destructive interference*

Sound intensity may be defined as the rate of sound energy transmitted in a specified direction per unit area normal to the direction. With good hearing the range is from about 0.000000000001 Watt per square meter to about 1 Watt per square meter (12 orders of magnitude greater). The sound intensity level can be formulated from intensity I by:

Sound Intensity Level = 10 x log (I/1.0E-12) dB

Note: 1.0E-12 W/m^2 normally corresponds to a sound pressure of about 2.0E-5 Pascal which is used as the datum acoustic pressure in air.

Sound intensity meters are the prime sources of intensity measurements. Such meters are becoming increasingly popular for determining the quantity and location of sound energy emission.

Sound decay with distance:

Sound changes with distance from the source are dependent on the size and shape of the source and also the surrounding environment and prevailing air currents. It is relatively simple to calculate provided the source is small and outdoors, but indoor calculations which can become a set of reverberant field calculations posing rather more complex problems.

If the noise source is outdoors and its dimensions are small compared with the distance to the monitoring position (ideally a point source), then as the sound energy is radiated it will spread over an area which is proportional to the square of the distance. This is an 'inverse square law' where the sound level will decline by 6dB for each doubling of distance. Line noise sources such as a long line of moving traffic will radiate noise in cylindrical pattern, so that the area covered by the sound energy spread is directly proportional to the distance and the sound will decline by 3dB per doubling of distance.

Close to a source (the near field) the change in SPL will not follow the above laws because the spread of energy is less, and smaller changes of sound level with distance should be expected. In addition it is always necessary to take into account attenuation due to the absorption of sound by the air, which may be substantial at higher frequencies. For ultrasound, air absorption may well be the dominant factor in the reduction.

Sound power level:

Sound power level, Lw, is often quoted on machinery to indicate the total sound energy radiated per second. The reference power is taken as 1pW.

For example, a lawn mower with sound power level 88dB (A) will produce a sound level of about 60dB (A) at a distance of 10 meters. If the sound power level was 78dB (A) then the lawn mower sound level would be only 50dB (A) at the same distance.

Speed of sound in air, water:

The speed of sound in air at a temperature of 0 deg C and 50% relative humidity is 331.6 m/s. The speed is proportional to the square root of absolute temperature and it is therefore about 12 m/s greater at 20 deg C. The speed is nearly independent of frequency and atmospheric pressure but the resultant sound velocity may be substantially altered by wind velocity. A good approximation for the speed of sound in other gases at standard temperature and pressure can be obtained from

$$c = (\text{gamma} \times P / \text{rho})^{1/2}$$

Where,

gamma =Ratio of specific heats

P = 1.013E5 Pa and

rho =Density.

The speed of sound in water is approximately 1500 m/s. It is possible to measure changes in ocean temperature by observing the resultant change in speed of sound over long distances. The speed of sound in an ocean is approximately:

$$c = 1449.2 + 4.6T - 0.055T^2 + 0.00029T^3 + (1.34-0.01T)(S-35) + 0.016z$$

Where,

T =temperature in degrees Celsius,

S =salinity in parts per thousand

Z =Depth in meters

Loudness:

Loudness is the human impression of the strength of a sound. The loudness of a noise does not necessarily correlate with its sound level. Loudness level of any sound, in phons, is the decibel level of an equally loud 1kHz tone, heard binaurally by an otologically normal listener. Historically, it was with a little reluctance that a simple frequency weighting "sound level meter" was accepted as giving a satisfactory approximation to loudness. The ear senses noise on a different basis than simple energy summation, and this can lead to discrepancy between the loudness of certain repetitive sounds and their sound level.

Loudness level calculations take into account "masking" - the process by which the audibility of one sound is reduced due to the presence of another at a close frequency. The redundancy principles of masking are applied in digital audio broadcasting (DAB), leading to a considerable saving in bandwidth with no perceptible loss in quality.

It is best, where possible, to avoid any unprotected exposure to sound pressure levels above 100dB. Use hearing protection when exposed to levels above 85dB, especially if prolonged exposure is expected. Damage to hearing from loud noise is cumulative and is irreversible. Exposure to high noise levels is also one of the main causes of tinnitus. The safety aspects of ultrasound scans are the subject of ongoing investigation.

3.3.2 Vibration

When something oscillates about a static position it can be said to vibrate. The vibration of a speaker diaphragm produces sound, but usually vibration is undesirable. Common examples of unwanted vibration are the movement of a building near a railway line when a train passes, or the vibration of the floor caused by a washing machine or spin dryer. Floor vibration can be reduced with vibration isolators; however there is often a penalty to pay in the form of a slight increase in the machinery vibration and its consequent deterioration.

Measuring Vibration:

Vibration is monitored with an accelerometer. This is a device that is securely attached by some means to the surface under investigation. The accelerometer produces a tiny electrical charge output, proportional to the surface acceleration, which is then amplified by a charge amplifier and recorded or observed with a meter. The frequencies of interest are generally lower than sound, and range from below 1 Hz to about 1 kHz.

It is sometimes more useful to know the velocity or displacement rather than the acceleration. In the case of velocity, it is necessary to integrate the acceleration signal. A second integration will provide a displacement output. If the vibration is sinusoidal at a known frequency, f, then an integration is easily calculated by dividing the original by 2 x pi x f (noting that there is a phase change)

Isolation of vibration and control:

Vibration problems are solved by considering the system as a number of springs and masses with damping. It is sometimes possible to reduce the problem to a single mass supported by a spring and a damper. If the vibration is produced by a motor inside a machine, it is usually desirable to ensure that the frequency of motor oscillations (the forcing frequency) is well above the frequency of the natural resonance of the machine on its support. This is achieved by altering the mass or stiffness of the system as appropriate.

The method of vibration isolation is very easy to demonstrate with a weight held from a rubber band. As the band is moved up and down very slowly the suspended weight will move by the same amount. At resonance the weight will move much more, but as the frequency is increased still further the weight will become almost stationary. In practical circumstances springs are more likely to be used in compression than tension, but the principles are exactly the same.

A further method of vibration control is to attempt to cancel the forces involved using a Dynamic Vibration Absorber. Here an additional "tuned" mass-spring combination is added so that it exerts a force equal and opposite to the unwanted vibration. They are only appropriate when the vibration is of a fixed frequency. Active vibration control, using techniques akin to active noise control, is now coming into use.

CHAPTER 3.4
WORKING & OPERATION

In order to provide an accurate estimate of detection ranges for a given target, it is necessary to know the noise level, propagation characteristics, processing system parameters, and the source level of the target of interest. During the 1980's the Navy's P-3 community had very few aircraft with the ability to make absolute sound pressure level measurements, making it difficult for the tacticians to know how to deploy their sensors and what they should be expecting in the way of performance. The Environmental Science Laboratory[(37,38)], ESL has designed a roll-on, roll-off monitoring and recording system that could be put onto any P-3 aircraft or any surface ship to acquire high quality, well-calibrated data.

Acoustic stimulation of the oil-bearing strata is accomplished by introducing special vibrations into the strata, which are as identical as possible to the natural rock matrix frequency, and/or fluids. These vibrations give rise to several effects in the fluids contained in the strata. They decrease the cohesive and adhesive bonding, as well as a substantial part of the capillary forces, thereby allowing hydrocarbons to flow more easily within the formation. The vibrations cause frictional heat which, in turn, reduces surface tensions and viscosity. The heating also may cause a partial evaporation of the lightest hydrocarbon fraction. It is obvious that reduced viscosity of the crude oil will favor mobility in porous medium thereby leading to an increase in production rates. However increase in production rates may not be sufficient to justify expenses incurred through consumption of electrical power.

Distributed Surveillance System:

Distributed surveillance systems are networks of sensors that can be spread over large ocean regions to provide information about the locations of submarines, surface combatants, commercial ship and fishing traffic, and even mining and weapons operations. Systems that are in development use advanced acoustic sensors that are integrated with state-of-the-art signal processing algorithms. ESL scientists and engineers have made significant contributions to the acoustic performance of distributed surveillance systems and have provided technical leadership in several key areas:

- Acoustic array configurations
- Algorithms for processing and display of acoustic data
- Adaptive beamforming algorithms
- Acoustic survey
- Mission planning acoustics
- Acoustic modeling and performance prediction
- System engineering
- System design concepts
- Early operational testing
- System Testing

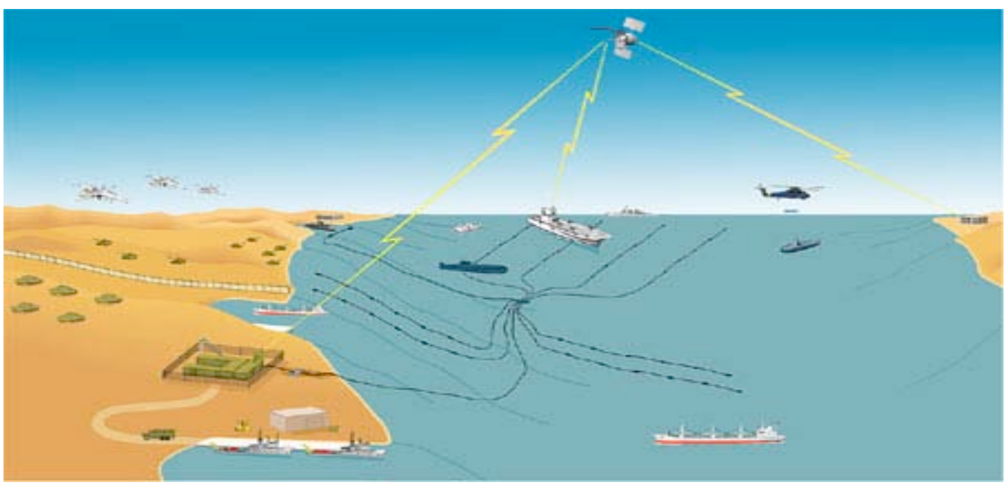

Fig. 3.6: *Distributed surveillance system*

ESL improves distributed surveillance system performance by conducting experimental and modeling research in acoustics and signal processing.

Signal Processing:

The Environmental Sciences Laboratory has a long history of developing state of the art signal processing algorithms. These algorithms, developed since the mid-1980s, have been installed in many Naval SONAR systems. ESL's signal processing sponsors include

SPAWAR, NAVSEA, ONI, ONR, and DARPA. Brief descriptions of some of ESL's signal processing efforts are given below.

Algorithmic Description

ESL is involved in several areas of signal processing. The staffs within ESL are acknowledged leaders in the fields that include conventional and adaptive beamforming, broadband processing, matched field processing and active signal processing.

Observation Tools for Remote Sensing: Doppler-based Sonars

UT is active in the development of new adaptive beamforming algorithms. Beamforming allows arrays of sensors to discriminate between signals in one direction and noise in other directions. ESL has used adaptive beamforming to improve SONAR performance in fixed and towed array sensors. ESL uses its understanding of environmental acoustics to design algorithms that take advantage of the noise enviroment within the ocean. These algorithms exploit the noise directionality and adapt, as the noise environment changes, to maximize the system performance, providing the operator with enhanced detection capability. This figure shows noise from an array, where an interferer is causing significant noise in all directions, when the array is beamformed using a conventional beamformer. The interferer is clear near the right side of the display, as the yellow and orange area that is cycling on and off. This interferer can be considered to be a jammer for the array, and the conventional beamformer sidelobes are not sufficiently low to restrict its azimuthal influence (i.e., the interferer is seen in all directions, albeit at lower levels when the beam is pointed away from the source). The noise from the adaptive beamformer, in contrast, shows enhanced noise characteristics in that the interferer at the right side of the noise field is significantly limited in its extent, the noise to the left is not affected by the jammer, and other contacts are visible (blue-green streaks on the left). Since the noise is much less with ABF, it will allow the SONAR operator to see targets of interest at much greater distances, enhancing detectability.

Broadband Processing:

ARL:UT and ESL are acknowledged experts in the area of developing broadband processing and display algorithms for Naval SONAR systems. ARL:UT developed the crosscorrelation processing scheme currently used several Navy systems. ESL continues to refine crosscorrelation and energy detection algorithms, providing superior situational awareness and detection capability to the SONAR operator.

Matched Field Processing:

Although adaptive beamforming can provide significant gains in performance, in some environments, and for some tactical situations, matched field processing can provide additional gains or information. Matched field processing couples signal processing with a thorough understanding of the acoustic environment. Environmental models are used to define signal representations used in the signal processing algorithms. This requires advanced simulation modeling capability. The signal representations are then used in specially designed signal processing algorithms to extract information on the contacts of interest.

In summary UT and ESL are known leaders in the SONAR signal processing arena. Advances in performance within a variety of systems, courtesy of ARL:UT technology, have improved the US Navy’s capabilities all over the world. ESL’s work in signal processing continues to hold promise for further enhancements, and exciting opportunities to influence and improve SONAR systems will continue to exist for many years to come.

Requirements for environmental compliance regarding marine mammals and noise create a need to develop methods to assess the impacts on marine mammal populations [(39)]. Several Navy ranges are installing new broad bandwidth sensors that are suitable for detecting and localizing the higher frequency calls of toothed whales as well as low frequency calls of baleen whales. The Naval Undersea Warfare Center is developing an advanced acoustic detection and localization capability for marine mammals at the Atlantic Undersea Test and Evaluation Center (AUTEC). If these systems are validated, they will provide important new, cost-effective monitoring capabilities. They also will offer the best opportunity to demonstrate methods to monitor long-term effects of noise in a fixed habitat. Lack of safe exposure levels for deep diving whales hinders assessment of the potential impact of Navy active acoustic operations, a requirement under the National Environmental Policy Act, and it hinders estimating the potential number of "takes" under the Marine Mammal Protection Act and Endangered Species Act. Research on the behavioral effects of noise on deep diving whales has been hindered by the lack of methods to observe behavior in sufficient detail. Tags are critical for monitoring potential disturbance responses of these deep diving species.

The primary objectives of this project are the following: (1) determine the feasibility of monitoring of marine mammals in select Navy undersea ranges to determine the availability, variability, and probability of detection and classification of the marine mammals; and (2) develop methods to determine the near- and long-term effects of Naval active acoustics on marine mammals in their natural ocean environment in select ocean areas of Navy interest.

A digital acoustic recording tag has been developed to measure the received level of stimulus at a whale while also measuring behavioral and physiological responses. The tag tracks responses of marine mammals (especially deep divers) throughout their dives. This information will provide an improved understanding of the functions and costs of behaviors in order to infer the biological significance of behavioral disruption. Methods for attaching these tags will be tested on deep-diving beaked whales in order to prepare for studies of how they respond to carefully controlled exposures of manmade noise. Whales within the AUTEC range will also be tagged in order to estimate the probability of range sensors detecting their vocalizations.

Fig. 3.7: *Self contained Acoustic Doppler Current Profiler™ Workhorse Sentinel. Credit: RD Instruments*

Fig. 3.8: *ADP™ devices (Credit: Sontek/YSI,Inc)*

Benefit:

Data on behavioral reactions of deep diving toothed whales and other cetaceans to Navy noises will make it possible to estimate the biological effects of naval operations. The database of vocalizations from tags will improve detection and species identification of passive location systems and will validate passive acoustic detection and localization methods. This study will help develop methods to test for long-term impacts of Navy noise on naval ranges.

CHAPTER 3.5
APPLICATIONS

Numerous observations accumulated principally during the last 40 years show that seismic waves generated from earthquakes and cultural noise may alter water and oil production. In some cases wave excitation may appreciably increase the mobility of fluids. The effect of elastic waves on the permeability of saturated rock has been confirmed in numerous laboratory experiments. Also, at the field level, high-power ultrasonic waves have been applied to down-hole cleaning of the near-wellbore in producing formations that exhibit declining production as a result of the deposition of scales and precipitants and mud penetration. It has also been applied to stimulate the reservoir as a whole. In this case the seismic frequency waves are applied at the earth's surface by arrays of vibroseis-type sources. This method has produced promising results, however further testing and understanding of the mechanisms is necessary.

It has been shown in laboratory studies that the application of elastic-wave excitation to saturated porous media can affect permeability and increase the extraction of hydrocarbons dispersed in the porous space. Similar observations have been obtained from the influence of earthquakes on the behavior of fluids in wells and reservoirs. Several patents for potential field services applying ultrasonic treatment of wells were granted in the 1950's and 1960's in the US and former USSR; however most activity and the beginning of actual field service date to 1970's. Research at that time was concentrated on the creation and industrial application of ultrasonic tools capable of creating strong acoustic fields inside the well-bore for cleaning. Practice showed that such tools might be very effective in removing scales, paraffins, and asphaltines from the formation, reversing the effects of mud penetration into the reservoir, as well as in preventing precipitation of salts on well equipment. Some of the effects that the acoustic fields can cause on the various fields of oil industry are further discussed.

3.5.1 Seismic Effect on In-Situ Fluids

Several cases where an earthquake caused changes in the production of oil and water were reported. Several important facts are reported. The significant increases in fluid production were observed near natural faults, especially anticlinal faults. This may be caused by the weaker attenuation of the seismic waves near the faults. This cannot be substantiated because the seismic intensity distributions were not reported. Another important fact is that increases in production were reported for a field were the acoustic intensity was as low as 3. This indicates that there is threshold intensity and that it is location-specific. The authors did not report enough quantitative data to determine if this is in fact why production increases were observed in Anapa in Northern Caucasus (former USSR) even though the distance from the epicenter was 100-km and the intensity in the field ranged from 3 to 5. Also the author did not provide an explanation for why the oil production increased in some cases and decreased in other case. For instance they reported that as a result of the July 12, 1952 earthquake in Southern California, in the same field, neighboring wells showed opposite responses to the seismic event. For example the production of one well increased from 20-BBL/day to 34-BBL/day while the production of a near by well declined from 54 BBL/day to 6 BBL/day.

3.5.2 Laboratory Studies

This section is the largest in the report. Many investigations were carried out to investigate the interaction between acoustic waves and a certain medium. The results can be divided to four groups:

- **The Effect of Acoustic Treatment on Oil and Water Percolation and on Water Floods**

Several investigators have reported that acoustic treatment enhances the recovery of hydrocarbons when used alone or in combination with water flooding. The first reported case was the work done by Duhon and Campbell[3.2] and will be discussed in further details in the section entitled **Enhanced Recovery**. Similar results were reported by Cherskiy et al. In both cases significant increase in permeability to fluids was reported. The authors also reported that for the same sample, applying pulsed mode excitation required 10 to 15 percent lower intensities than continuous excitation. No discussion was provided on the significance of this phenomenon or on its physical cause(s). Neretin and Yudin reported that there was a significant increase in the displacement of hydrocarbon fluids by water through loose sand. The only quantitative result reported was that the hydrocarbon yield increased by 65 to 85 percent. Gadiev reported the results of subjecting hydrocarbon saturated loose sand to a sonic field during displacement by water. The main observation was the significant increase in displacement times in some cases by as much as 15 percent. Other results were reported as well, however the absence of quantitative data made it impossible to discuss the results in more detail.

- **The effect on Viscosity and Surface Tension**

Gadiev, in the previously mentioned work, reported that the application of the acoustic field reduced the time of penetration by hydrocarbons in capillary tubes, however no discussion was provided of the subject. Also the temperature and the initial viscosity of the fluid were not reported. Gadiev also measured the surface tension of a transformer fluid subjected to an acoustic field. He reported that surface tension chances depended on both frequency and time. The experimental setting was not discussed, and therefore the effect of other parameters cannot be ignored. Other results were reported on the positive effect of acoustic excitation on the viscosity of various polymers.

- **Paraffin removal**

Paraffin removal was studied extensively by Abad-Guerra. He concluded that permeability to oil increased by 7 to 51 percent for different samples subsequent to acoustic treatment. He also reported that temperature increased in one experiment from 31 to 76 degree centigrade. This increase was not correlated to the cloud point of the paraffin or to the properties of the acoustic field. Success in paraffin removal was also reported by Horbit, and also by Dvali and Sumarokov.

- **Effect of Treatment at Low Intensity**

Several studies focused on the effect of low intensity acoustic treatment. The work was aimed at developing technology to advance the application of surface vibration to stimulate reservoirs. Dyblenko et al. applied a 200-HZ acoustic field to a core sample saturated with kerosene. He noted that the yield of kerosene from the core increased by 12 percent. Also, Simkin et al reported a significant increase in kerosene mobility through loose quartz. They reported that the yield increased from 32 percent under no stimulation to 60 percent.

3.5.3 Stimulation of Production Wells

Acoustic treatment of producing wells is beneficial in several ways. There were several authors who attended the potential of this technology for cleaning of petroleum containing strata. Also, mobility of fluids in the formation or those introduced such as chemicals and mud is mentioned. This technology may also be used for secondary and tertiary recovery. Some investigations were carried out and promising results were obtained. For instance, an ultra-high frequency tool that operates at 58 MHz was used by Morris to clean near well bore blockage caused by precipitation of salts, the growth of scales and also as a result of mud penetration. The treatment was successful in 81 percent of cases. Tools operating in the intermediate frequency range of 5 to 50- kHz were used successfully to clean various formations. Kuznetsov and Efimova reported an overall productivity increase of 15 percent after the treatment of a fine-grained sandstone formation with siliceous clay and carbonaceous cement. Treatment at the same intensity and frequency was reported in some cases to be successful while negative results were observed in other cases. These results were reported by Simkin et al. with no explanation. Also, others did not provide any information about the geology of the formation, the gas content of the reservoir fluid, or the base line production data used for comparison. The intermediate frequency range seems to be most efficient when used in conjunction with an intensity range of 0.1 to 0.5-Watts/cm^2. Shaw Resources used their Sona tool to test the acoustical response of two wells in California. The rate of success was 40-50 percent and the effect lasted for 10-15 days for the first tests, and one month for the second tests.

Reservoir Stimulation with Surface Vibrators

Few field tests using conventional seismic prospecting units were conducted by Soviet scientists in an effort to simulate an entire region of the reservoir. Some success was reported, such as with the treatment of Abuzi field. The reservoir depth is 1200-meters, and the pay zone is located 10-meters below the datum. In one test a 20-ton unit was placed at 250-meters from a marginal well producing at a water cut rate of 90 to 92 percent. The oil cut increase up to 20-25 percent after several days of stimulation and the effect lasted for 60 days after stimulation was terminated. These results, though promising, cannot be used to conclude that this technology can be applied as a standard practice to enhance oil recovery. The field tests are scarce and sufficient data are not available for further development of this technology.

3.5.4 ENHANCED RECOVERY

3.5.4.1 Improvement of Oil Recovery by Addition of Ultrasonic Treatment to Water-Flooding

Some investigators noted the potential for the application of ultrasonic technology to oil recovery. In particular, focus was directed to the improvement of oil recovery in a system were one fluid is being displaced with a less viscous fluid[3.2]. Duhon and Campbell[3.2] reported its effect on recovery. They reported that for a torpedo sandstone core, a maximum increase of 14.7% in recovery at low ultrasonic frequency was realized. They also showed that recovery decreased as the acoustic frequency was increased.

The work also revealed a decrease in instantaneous water-oil-ratio. The authors pointed out that this is an indication of a more uniform flood front, or a more efficient displacement mechanism. The permeability ratios (k_w/k_o) were significantly reduced with ultrasonic introduction to the system. The investigators determined that the mobility ratios are a function of only the permeability ratios because temperature essentially remained constant during the experiments. Therefore they concluded that the viscosities remained constant. The work also demonstrated the effect of the viscosity of the saturating fluid on the effectiveness of the ultrasonic treatment. The ultrasonic treatment was more effective for less viscous fluids. The authors postulated that the increase in recovery is affected by the cavitation phenomenon. The shock wave caused by the collapse of gas bubbles can induced fracturing in the surrounding matrix; therefore, the interconnected flow channels are enlarged leading to an effective increase in porosity and permeability. The investigators also postulated that the shock wave can supply enough energy to overcome the capillary tension in some channels. This leads to the recovery of a portion of the trapped oil. The effect of the ultrasonic treatment on localized flow was also investigated. The results indicated that injectivity increased subsequent to the ultrasonic treatment. The study reported that no attenuation was present.

3.5.4.2 Removal of Mud Solids and Fines from the Near-Wellbore Region

A drastic decrease in effective permeability provoked by near-wellbore damage can significantly diminish the efficiency of oil recovery. Near-wellbore contamination with mud solids and loose fines is considered to be a significant problem for oil producers. An investigation was carried out to study the potential for the removal of these contaminants using ultrasonic treatment. The technology is an economically attractive alternative to conventional treatments such as the pre-treatment of drilling fluids, hydrofracturing, chemical injection, and additional perforation.

Definitive improvement in permeability was reported and it was more significant at higher ultrasonic intensity. A four-fold increase in permeability was observed for, brine-saturated, Berea sandstone contaminated with mud. Permeability increased by a factor of 2.25 at irreducible water saturation with oil. A permeability increase by a factor of 1.5 was observed for a mud-contaminated Indiana limestone core. This indicates that the effectiveness of cleaning is contingent upon the physical properties of the rock. Ultrasonic treatment of brine-saturated sandstone contaminated with fines resulted in an increase in permeability by a factor of 7. A contrast was observed between mud and fines contamination. The mud only contaminated a 2.5-inch section of the 7.5-inch long core whereas the fines contaminated the whole core. Ultrasonic treatment cleaned the contaminated section in both cases. The authors also reported a decrease in ultrasonic intensity as the ultrasonic wave disseminated farther from the source. They suggested that poor coupling of the ultrasonic source to the core might be the cause for this. The authors[3.10] concluded that acoustic streaming (a rotational motion in the fluid due to ultrasonic energy) is the major contributor to the cleanup because of the low intensity of the ultrasonic source. They postulated that cavitation only contributed to the removal of mud particles located near the surface.

3.5.4.3 Ultrasonic Removal of Asphaltene Deposits during Oil Production

Many crude oils contain varying amounts of asphaltene fractions. The presence of asphaltenes can cause serious problems due to deposition from the crude during secondary or tertiary oil recovery operations. Deposition was observed during miscible floods where two fluids such as carbon dioxide and water are injected sequentially. Also deposition can occur due to changes in temperature and pressure. Deposition occurs in the area surrounding production wells.

Asphaltenes are dark, solid elements of the crude. It is presumed that these solids are dissolved in the crude because resins attach to their surfaces and thereby form micelles. The tendency for the precipitation of asphaltene is directly correlated to the amount of resins and to the temperature and pressure of the reservoir. Asphaltenes precipitate during acid stimulation or carbon dioxide injection because thermodynamic equilibrium is disturbed. Also precipitation is provoked by changes in pressure. Hasket and Tartara reported that asphaltene precipitation diminished with depth during a field study conducted at Hassi Mesaoud field in Algeria. They concluded that precipitation occurred when wells were operating at pressures above the bubble point of the oil. The bubble point pressure of this 42° API gravity oil ranged from 147 to 199-atm. The introduction of shear forces can affect the dispersion of asphaltenes. Use of an ultrasonic source is a potential alternative to other conventional expensive techniques. Current techniques rely heavily on the utilization of chemical dispersants such as naphthalene-based solvents. Such techniques are becoming less popular because of tighter environmental regulations.

Gollapudi et al.[3.11] investigated the use of ultrasonic energy to disperse asphalt precipitates. Two types of tests were conducted. In the first scheme, a thin layer of asphalt was spread evenly on the bottom of a small laboratory glass beaker. Water and kerosene were added to it. The ultrasonic energy was drawn from a 250-watt generator at a frequency to 10-kHz. Dispersion of asphaltene was observed in both mediums. The cleaning was more effective with the presence of kerosene. Maximum cleaning was realized for water and kerosene at a frequency setting of 5-kHz for a treatment time of one minute and 7.5-kHz for a treatment time of three minutes respectively. Frequency increase did not result in any significant cleaning at frequencies above 5-kHz for kerosene.

In the second set of experiments, sand, asphalt, and kerosene or water were packed in a laboratory flow-cell. The 1-inch pack was placed on top of a sand column. Flow-rate measurements were monitored to quantify the effect of the ultrasonic treatment on the column. The permeability in the top 1/2-inch sand/asphaltene mixture was increased by 494 times for water and 275 times for kerosene. The mixture had an initial permeability range of 28 to 30-Darcies and was treated for 2-minutes at 7.5-kHz. The bottom portion of the pack was cleaned less effectively. The top one to one and a half inches of the sand column was contaminated with asphaltene. This indicates that asphaltene precipitated at an increasing rate farther from the ultrasonic source as a result of attenuation. The investigators did not quantify the precipitation gradient.

3.5.4.4 Ultrasonic Removal of Organic Deposits and Polymer Induced Formation Damage

In this study, the authors described a technique to remove paraffin and polymers from damaged Berea sandstone cores [3.12]. The apparatus and experimental procedure are similar to those described previously in Reference 3.10. The procedure for damaging the core with hydroxyethylcellulose (HEC) is identical to the procedure for damaging a core with fines. The damage with paraffin differed because it was necessary to introduce the contaminant above its cloud point. To accomplish this, the paraffin was introduced at 65-°C. The apparatus was then back-flooded with a mixture of kerosene and paraffin.

Ultrasonic radiation at 20-kHz at an energy input of 1.4-KJ was sufficient to completely remove the paraffin from the 6.35-cm section of the core located nearest to the transducer. The permeability of the second 5.08-cm section also doubled. The cleaning of HEC was not efficient. A power input of twice that used to clean the paraffin only resulted in 50-percent increase for both sections. The authors concluded that the use of acoustic energy alone is not effective for cleaning polymer damage in that particular case.

3.5.5 PRODUCTION ENGINEERING

There has been a recent trend in the industry to drill more horizontal and inclined wells. The well is drilled parallel to the pay zone and thereby increasing the surface area of the well that is exposed to the pay zone. This results in an increase in production. These wells are especially attractive for shallow formations, were multiple vertical wells may be needed to deplete the pay zone. Production logging of horizontal and inclined wells has not developed at the same pace as drilling and completion technology. Conventional production logging is not adequate for such wells; as segregation of fluids due to gravity makes interpretation of data difficult, and rarely do conclusions drawn from such data describe the reality of the fluid flow in the well. It is important to acquire such data for use in future depletion schemes. The use of an ultrasonic technique for this purpose is desirable[3.8]. Sensors can be integrated with the well casing to avoid erosion and flow disruption. Also ultrasonic techniques can be used at high temperatures and pressures. Sound pulses interact in a distinct way with liquid, water and gas. Doppler frequency changes can be used to monitor production. This frequency is controlled by sound velocity in the specific medium, source frequency, and velocity of the fluid. Therefore, analyses of reflected echoes are used to determine velocity, density, and composition of the fluid.

Researchers at IKU Petroleum Research developed a new UDV technique for this purpose. The researchers attempted to overcome some of the obstacles posed by the physical setting. The equipment must detect rapid changes in the flow of the fluids. Furthermore, scanners must be incorporated in the apparatus in order to filter echoes from stationary sources, such as the well casing. Also techniques for distinguishing echoes generated by primary and higher order scattering are necessary. These echoes are generated at two-phase contact zones where gas bubbles and liquid droplets form. Experimental work in the lab revealed the existence of multiple sensitivity maxima, with the highest detection region located at the tip of the probe. This may cause ambiguity because it is difficult to know the source of scatter. Field tests were performed in a North Sea well that is characterized by low water-to-oil ratio and high sand content. The well is deviated 50-degrees from the horizontal axis. The well was shut-in, and the probe was placed 50-meters downstream from the wellhead. During shut-in, low-frequency activity was observed resulting from gas influx. The well was producing at a constant rate of 250-liters/minute. At the beginning of production, a steady flow was observed indicating laminar flow; this was followed by more turbulent flow period. Lastly, this period was followed by a period when gas flow was detected. The above experiment was performed with a pulsed ultrasonic source operating at 5-MHz and other experiments were performed at lower frequencies. The authors found that better results were obtained at lower frequencies, especially during the free gas flow condition. The researchers were able to improve the quality of acquired data by isolating Doppler signals generated by specific flow volumes.

Use of an Ultrasonic Flowmeter for Gas Flow Measurement, and for Production Characterization

In this Investigation, sonic differential time-of-flight, static pressure, stagnation temperature, bore diameter, and tool depth, were used to measure gas velocity, density, and volumetric flow rate. Sound velocity in the fluid media was calculated. The major advantage of this technique is that desired properties are acquired independently of the physical properties of the gas. Also the instrument can detect flow rates as low as-0.02 CFM. Irregularities in the velocity log profile give important data such as gas entry locations.

3.5.6 DRILLING AND COMPLETION

3.5.6.1 Kick and Loss Detection during Drilling

Two significant and potentially dangerous situations, which can arise during drilling operations, are kicks and mud loss. Kicks occur when the pressure build-up in the borehole exceeds the pressure exerted by the weight of the mud column. Mud loss occurs when mud penetrates the rock formation surrounding the borehole. Both conditions can lead to blowouts. Significant drilling downtime and mud loss leads to economic losses. Also personnel and equipment are exposed to a significant level of risk.

Several Delta-Flow (flow-out minus flow-in) techniques have been developed. The classical method for this purpose is the analysis of the volumetric gain or loss in the mud tanks. This method suffers from a number of limitations that reduces its accuracy. Poor monitoring of mud levels results from agitation in the tanks, the number of tanks, the total surface area of the mud, and poor accuracy of the level sensor. Typically a 10-Barrel change is necessary to detect problems in the mud circulating system. Analysis of volumetric changes in the mud tanks is accurate to plus or minus 20-Barrels.

Flow paddles are also used. However, only rough estimates based on the density and viscosity of the mud are realizable. The flow paddle is unreliable for use in recognizing small flow increments because it requires correct installation and continuing maintenance. The only reliable technique is to utilize two electro-magnetic flow meters: one in at the outlet of the triplex pump and the other in the return line. The installation of the second flow meter requires the return line to be fitted with a large U-shaped tube because the flow meter only operates when fully immersed. This technique has been used to achieve an accuracy of 50-gpm on the delta-flow; but can only be used for water-based muds because the medium must be electrically conductive. As a consequence of these limitations, a new technique for out-flow measurements has been developed.

The new technique utilizes an ultrasonic level sensor in the return line. The system measures the time of traverse of an ultrasonic wave from the source to the surface of the fluid and back to the source. Three heat sensors are used to determine the temperature in this gap, as it is necessary for the determination of the distance traveled by an ultrasonic echo. A Doppler velocity probe is installed downstream from the level sensor. These two instruments are connected to a computer located 500-ft from the well-bore. The computer receives five measurements from a sensor control unit. The inputs are: velocity, uncorrected fluid level, and 3 temperatures. A reliable in-flow measurement system is used to measure and send data to the computer, which then calculates delta-flow and controls delta-flow alarms. Other studies have shown that an accuracy range of 25 to 50-gpm is adequate for detection of delta-flow. The new technique was tested in the field, and has proven to be reliable for mud-circulation testing.

3.5.6.2 Use of Borehole TeleView (BHTV) to Improve Completion

Problems in characterizing a dolomite formation in wells drilled during a 1984-1985 infill drilling-program in the San Andres zone of the Hobbs Field, Lea County, New Mexico. This field is operated by Shell Western E&P Incorporated and is under water-drive from a nearby aquifer. Higher water cuts were realized at existing wells in the region where vugs (voids in the dolomitic matrix) that were not identified by conventional logs (gamma-ray, sonic, laterolog, and microspherically focused log) existed. The BHTV, used at Shell and its subsidiaries since 1983, was utilized to supplement these other logs.

The BHTV is an ultrasonic scanning device that consists of a rotating pulse-generating transducer and a flux gate magnetometer (used for orientation), the probe is linked to a computer at the surface. The induced ultrasonic wave scans an 8-mm cylindrical section of the well at an angle of 1.5-degrees. The acquired data are used to generate three plots. The polar log displays 250 round trip durations of the wave during each rotation of the BHTV and results in improved resolution. The Amplitude log displays amplitude readings for the same number of round trips. Variations in amplitude result from changes in lithology, hole size and shape, and mud weight. The amplitude data are displayed as an image for ease of interpretation. The image ranges from black to white, black representing consolidated rock and white representing voids. Shades of gray are added for continuity and improved interpretation. The transit time of the wave is also used to generate a third plot incorporating 16 shades of gray, each shade is coded as a function of the travel time allowance. The image depicts a relief map displaying white “ridges”, gray contours, and black valleys depending on the time required for the wave to be reflected by a particular section of the scanned area. The BHTV is mounted in the casing shoe at the bottom of the casing, where other logging devices are typically mounted. The interpretation of BHTV logs led to the implementation of corrective measures to seal water penetration regions in the infill wells. The results were then correlated to offset wells and used to execute similar corrections.

3.5.7 RESERVOIR EVALUATION

3.5.7.1 Detection of the Formation of Gas Bubbles in Depletion Experiments

Natural gas is released from reservoir oil during primary depletion. The Reservoir pressure diminishes as material is transported out from the reservoir. When pressure drops below the bubble point, gas bubbles begin to form. The nucleation and growth of these bubbles are influenced by the fluid properties, nature of rock formation, and the degree of super-saturation. A reliable indicator of the progress of the process is the nucleation rate, J.

Laboratory experiments need to be carried out to obtain data at different conditions. The conventional technique is to monitor volume changes of the fluid. The classical approach is to observe the displacement of a meniscus in a capillary tube subsequent to initial detection of a volume change. This technique was improved, for low super-saturation, by the incorporation of an electric bellows. This enhancement increased the resolution to 0.05-mm^3. Differential volume measurement techniques are limited by the inability to detect the location of gas bubbles. Also inaccurate measurements can be made as a consequence of the changes in formation volume. Furthermore, another problem is the increase in the difficulty of observing the meniscus at high temperatures and pressures. A new technique was developed to overcome these limitations.

The new method is based on the change in the travel time of ultrasonic waves in different mediums. The sound velocity increases dramatically as it travels from a liquid medium to a gas medium. Detection of these changes permits accurate monitoring of bubble nucleation. An apparatus was assembled for this purpose. The assembly consists of a pulse generator, an oscilloscope, a scanner, an amplifier and a probe. The probe incorporates eight evenly spaced transceivers configured for attachment to a cylindrical rock sample, 4-cm in diameter and 7-cm long.

The rock sample was saturated with carbon dioxide dissolved in water and methane dissolved in dodecane separately. The fluids were confined initially at a 3×10^5-Pa. absolute pressure and at 25-°C. The sample was coated with a resin and sealed at one end. The other end was connected to a gas chamber via a capillary tube. The pressure was lowered quickly from the super-saturation pressure to the operating pressure and time-counting was initiated.

The first test was conducted on a limestone sample with a porosity of 38-%. Gas nucleation was detected 5.45 minutes into the experiment by the first transceiver and the other transceiver thereafter detected bubble formation. All transceivers were sending stable signals 45-minutes after initialization. At this time the investigators concluded that critical gas saturation had been attained. A sandstone sample was tested at increasingly high super-saturation pressures. The data showed a definite increase in nucleation rate as super-saturation pressure were increased.

The investigators also conducted experiments at a higher confining pressure. The rock sample was saturated with water at an absolute pressure of 10^6 -Pa. Water was displaced with a water-glycerin mixture. The water-glycerin mixture was then displaced by a gas. Both displacement front and progressive gas saturations were observed.

3.5.7.2 Ultrasonic Saturation Mapping in Porous Media

Accurate data about saturation are important for the successful implementation of secondary and tertiary oil recovery techniques, specifically miscible and immiscible fluid displacement. This data are also important for the development of accurate reservoir simulators. Laboratory techniques are used to characterize fluid saturation. Techniques such as gamma-ray and X-ray absorption are used with various degrees of success. It should be noted however that these methods were developed for use in the medical field and extension to other areas of study requires extensive and expensive safety measures and personnel training. Consequently, research is underway to find and develop new and more accurate techniques.

One alternative to these techniques may be to use acoustics for these fluid saturation studies. The technique is based on the contrast in relative sound velocity in different mediums. An automated data acquisition system was developed. The system is assembled using a pulse function generator capable of transmitting at a frequency of 330-kHz. The generator is connected, in parallel, to a time counter. The transmission of a pulse causes the counter to initiate the recording of time. The pulse is then regulated by a scanner prior to transmission to a series of transducers connected to a transparent medium. The generated mechanical waves propagate through the medium until penetration is complete. At this point, the waves are detected by a series of receivers at the opposite end of the medium. The signals were sent sequentially to an amplifier were they are multiplied until the threshold of detection of the time counter is reached. The recording then stops. The signals are digitized using an oscilloscope and transmitted to a computer that is programmed for data analysis and for control of the other elements in the assembly.

Experiments were performed using a 16 × 10 × 1.3-cm quartz medium. A water and glucose mixture was used to displace water in one miscible flow experiment. A mobility ratio of 1/300 (viscosity of displaced fluid / viscosity of displacing fluid) was used to insure a smooth displacement front. The high composition gradient between the two fluids affected the creation of a dispersion front and this was clearly detected by the probe. Visual and ultrasonic images were obtained and compared and a good correspondence was observed.
Oil injection was used to displace a water-glucose mixture. This immiscible displacement was carried out at a mobility ration of 30. A comparison was made as discussed previously, and to a large extent, the ultrasonic data matched visual observation. In addition, experiments were performed to observe the spatial and temporal resolution of the ultrasonic apparatus. A 70 × 50 × 10-mm aluminum block was placed in a water bath and the horizontal and vertical resolution of a single transducer was monitored. The resolution was 5.2-mm in one direction and 3-mm in the other direction. The results deviated slightly from those expected, as the transducer was 5.6-mm wide and 2-mm thick. The temporal and saturation resolutions were concurrently performed using gamma-ray measurement. The water was displaced laterally by brine. Both instruments measured similar values, use of the ultrasonic technique yielded “smoother” saturation measurements.

3.5.8 WELL LOGGING

Use of Acoustic Data for Interference Testing

A field investigation was carried out to determine whether interference existed between wells in Owl field in North Eastern British Colombia, Canada. It was originally hypothesized from available data that oil in the field was present in three "closed" pools. From the onset of production, initial pressures at the producing wells did not differ. This led to speculations on whether the oil zones were separated by sealing physical boundaries. At the time of the investigation, eight wells were producing. These wells are shown on Figure 3.9. Only three wells were flowing, three wells (Wells 06-09, 12-09, and 15-09) were under pump, and one well was produced by a plunger lift mechanism. A previous investigation in 1991 indicated a wide range of reservoir pressures. It was decided to group the wells into three pay zones and to draw a geological map to represent the internal permeability data. These data were re-analyzed in 1995, as a requirement for a pending sale. It was decided that the initial thinking concerning the reservoir configuration was incorrect as pressures after four years of production were higher than the initial pressures. A new interference study was performed to determine whether communication existed among the three zones. This study was undertaken given that water flooding of the field was under consideration.

Several problems were posed to the investigators. The field has been in production for a long period of time and consequently gas saturation has increased significantly. Furthermore, the presence of pumps in the wells dictated that a non-intrusive surface monitoring method be used, as the removal of the pumps from the wells is cost prohibitive. Also, given that pressure changes due to interference between and among wells are typically small and difficult to detect, an alternative to the typical surface measurement that is limited with respect to sensitivity, was needed.

A decision was made to utilize a newly developed acoustic Surface Measurement System (SDS) and bottom hole acoustic pressure sensors. The SDS consists of portable probes equipped with electronic pressure sensors, and are designed to yield improved temperature compensation. Subsequently, a theoretical simulation was carried out. The results indicated that an interference response of 25-kPa was to be expected. However,

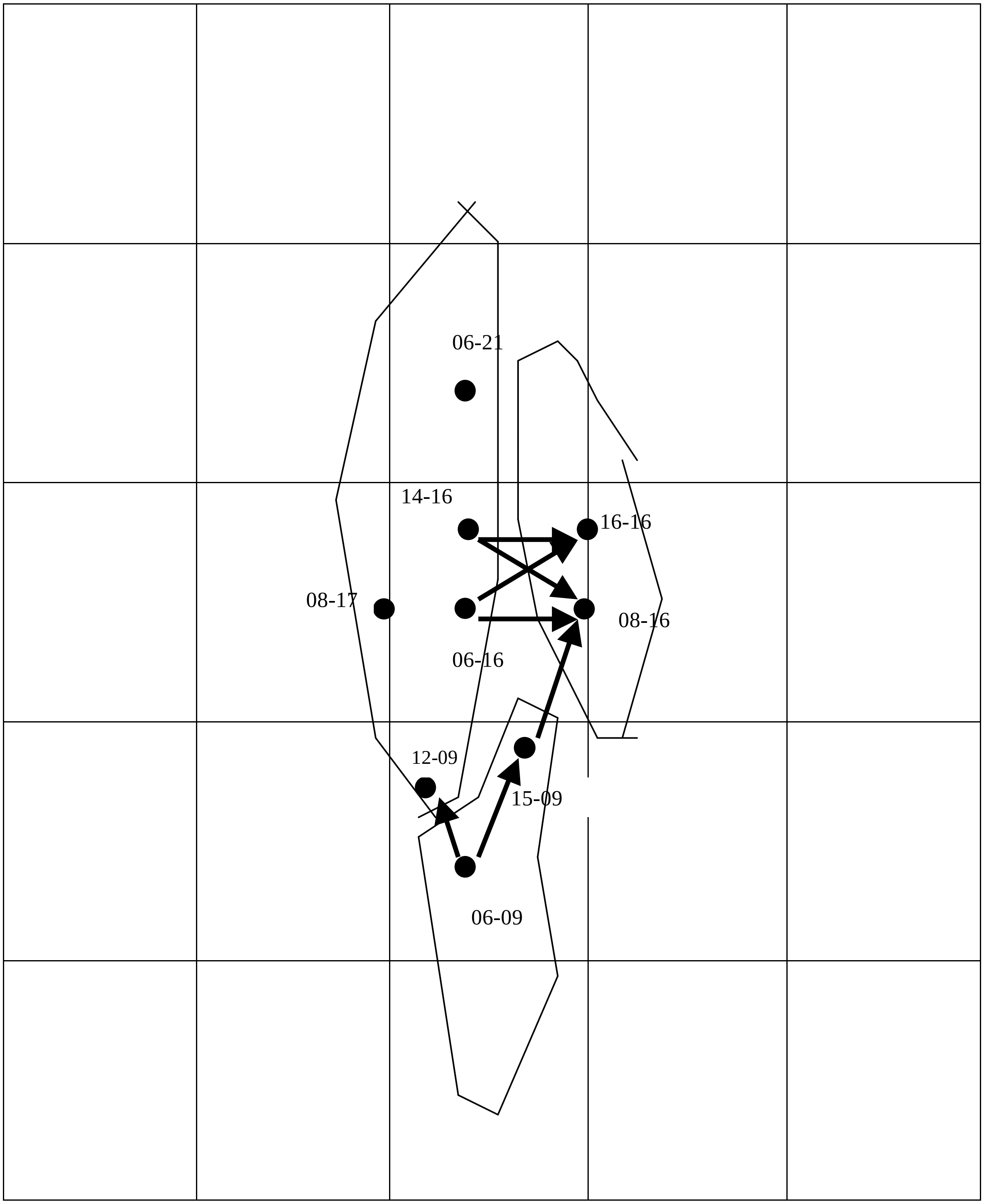

Figure 3.9: *Schematic of the Owl field showing surveyed wells and planned interference as well as the original geological boundaries*

there was concern due to the uncertainty in the variables used for simulation. It was decided that at the time, the selected equipment was best for the tests that were planned.

The investigation was sequentially divided into three phases. During the shut-in phase from November 20 through November 24, 1995, the pumping wells were first shut-in, followed then by the other wells. Surface measurements were performed from November, 1995, through January, 1996. Ambient temperature ranged from –25 to –40-°C with typical temperature swings of 20-°C between day and night. SDS probes were advantageous for these conditions because calibration at low temperatures was possible, and because of their ability to detect and compensate for fluctuations in temperature. Fluid level was measured using manual dual-channel recorders equipped with cartridges to generate acoustic signals. The surface pressures were also measured using digital gauges. Acoustic interference measurements were performed in the second phase. Multiple data acquisitions were needed to perform bottom hole pressure calculations. Representative fluid compositions and PVT data were required as well as well-bore schematics, tubing tally, and up-to-date directional surveys of the wells. Also, casing pressures and fluid levels had to be determined. The calculations were performed using an Equation Of State (EOS)-based model tuned in the laboratory to perform calculation above and below the bubble point of the reservoir oil at the reservoir temperature. The output of the model was in good agreement with PVT data.

Field tests were then performed in Wells 12-09 and 15-09. Well 06-09 was returned to production and Wells 12-09 and 15-09 were shut in. The pressures in Wells 12-09 and 15-09 initially increased and then declined by 25-kPa, and 41-kPa respectively. This decline in pressure was attributed to the interference effect of Well 06-09. The acoustic measurements and the calculated pressures were in good agreement with the exponential integral solution for this physical case.

Finally, bottom hole interference tests were performed in Well 08-16. Well 12-09 was placed on production so that all the wells offsetting Well 08-16 were in production; the other offset wells are Wells 06-16, 14-16, 06-09, and 15-09. Well 16-16 was left shut-in because it was believed to be in the same pool as Well 08-16. Pressures in Well 08-16 declined to 51-kPa confirming that all wells were located in the same pay zone.

This investigation proved that acoustic monitoring is an effective tool for use in interference testing. The technique is advantageous especially for wells equipped with pumps. Also the technique could be used in extreme weather conditions given that the acoustic tool is equipped with technology to compensate for temperature and for recording temperature fluctuations. The accuracy of the field tests were enhanced given that they were used in conjunction with an results EOS based model.

Research on the use of Sonication for remediation of contaminated soils and damaged oil producing wellbores has been undertaken at The Pennsylvania State University. Projects such as: Effect of sonication on removal of petroleum hydrocarbon from contaminated soils by soil flushing method, Young, K.: et al 2000; Effect of Ultrasonic radiation on rock permeability, Ozdemir, M.: et al 2004; a qualitative analysis of near-wellbore thermal field generated by acoustic waves, Rejepov, D.: et al 2004. These researches are driven to expand the applicability of acoustics to both the oil and gas and environmental remediation industries.

Nearly fifty percent of the drinking water consumed in United States comes from ground water. Any contamination to the ground water and soil can have serious impact on public health. Among the numerous causes for contamination to ground water and soil, spills of petroleum hydrocarbons such as gasoline, motor oils, and diesel fuel from underground storage tanks (USTs) is a major source of contamination. The objective of the study by Kim Young was to develop an effective and economical technique to enhance soil flushing for removing petroleum hydrocarbon from contaminated soil deposits. To meet this goal, the effectiveness of ultrasonic waves on extraction of petroleum hydrocarbon from the contaminated soil was investigated under a broad range of conditions including soil type, density levels, flow rates, temperatures and energy levels of ultrasonic waves.

Considering the effect of ultrasonic waves on water flow, the study focuses on two aspects: the flow induced by sonication and sonication effect on the hydraulic conductivity of the test soils. It was observed that a soil having a less attenuation capacity will transmit more wave energy to produce a greater hydraulic head. As a result, the peak hydraulic heads induced by sonication are greatest for fine aggregates followed by Ottawa sand and natural soils. Reddi et al (1993) also investigated the effect of ultrasonic energy on enhancement of the permeability of clayey soils. They observed an increase in the permeability of all tests and attributed the increased permeability to the removal of particles smaller than clay and colloidal size particles in the test specimen. But in the test conducted by Kim at The Penn State University, little observable fine particles were seen in the effluent. Therefore, for the test soils, the increased permeability due to sonication is attributed primarily to particle agitation and dislodging.

The results for the sonication effect were obtained for the condition that the ultrasonic stress waves propagate in the same direction as that of water flow. When the direction of stress wave propagation is opposite to that of water flow, no significant sonication effect on water flow rate is seen. This can be attributed to the combined effect of sonication-induced water pressure and sonication-increased hydraulic conductivity. When the acoustic wave propagates in the opposite direction to water flow, the wave-induced water pressure counteracts the hydraulic pressure of water flow, resulting in a reduction in hydraulic gradient. Although the hydraulic conductivity is increased, sonication may not significantly increase the discharge velocity of water, which is equal to the product of hydraulic gradient and hydraulic conductivity. Such an observation has been reported by Iovenitti (1995). Based on this observation, it was concluded that the hydraulic conductivity is not affected by sonication without due consideration of the hydraulic gradient effect.

Finally, it is observed from the results that:

- Sonication can induce seepage in porous media, where the seepage caused by hydraulic head is attributable to the application of sonication. The rate of sonication-induced seepage varies with soil type and sonication power.

- Sonication can increase the coefficient of hydraulic conductivity (or permeability) of soils. The degree of increase depends on soil types and conditions, hydraulic heads and sonication power.
- Sonication can enhance the removal of petroleum hydrocarbon from contaminated soils. The efficiency of contaminant removal due to sonication depends on soil types and conditions, hydraulic gradients and sonication power.
- The soil flushing method with sonication has a great potential of becoming an effective and economical method for removing petroleum hydrocarbons from the contaminated ground.

Effect of Ultrasonic radiation on rock permeability

Formation damage in oil producing wells is an important problem in the oil industry. The main cause for near wellbore damage may be due to the precipitation of asphaltenes and/or paraffins around the producing formation or the plugging of the pores due to fines migration, clay swelling or invasion of mud particles during drilling. It is evident that remediation techniques of the near wellbore damage, which are economical and environmentally benign, are needed in the petroleum industry. By considering the above aspects, the acoustic technique for cleaning near wellbore formation damage is under development. This technique uses high frequency sound waves to excite the particles and facilitate their flow into the well.

The effectiveness of ultrasonic waves in removing wellbore damage was investigated at laboratory scale at The Pennsylvania State University. Berea sandstone cores were first damaged by injecting fresh water and the damaged cores were subjected to sonic stimulation with and without a solvent. Acoustic energy was applied to fired and unfired core samples in both co-current and counter-current flow directions while ethanol was used as the solvent. Liquid permeability of the cores was monitored as a function of time before, during and after the application of acoustic energy. The results have shown that sonic stimulation was more effective in co-current direction and the combination of sonic stimulation with the solvent did not create a significant improvement in the permeability value. The observations made from the experimental work were listed below:

- Inspection of fresh water resulted in damage to the porous media; the application of sonic energy produced an increase in the permeability that did not appear to be a function of power output level,
- Although surface tension does not appear in Darcy equation, it affects the measured permeability of the rock. The results show that the measured liquid permeability increases with ethanol concentration. Since the liquid surface tension decreases with increasing ethanol concentration, it appears that measured liquid permeability values may depend on the solvent used. This effect may be tied to wetting properties of the rock,
- With fired and dried core samples, it appears that sonication in co-current flow direction gave higher permeability values when compared with the counter-current flow arrangement. This observation is in agreement with the observations made by Kim Young, 2000,
- Using fresh water flow, higher permeability values were obtained with fired cores, thus confirming that firing reduced the swelling potential of the Berea sandstones,
- It is suggested that once the core is subjected to sonic stimulation, additional application of sonic energy and the use of a higher power output have little effect on the permeability of the sample.

3.5.9 Engineering applications

When the atmosphere is considered with a view to acoustics, two major areas of interest are found. The first is the effects on sound due to the vibrations and heterogeneities of the earth's atmosphere, such as the random deformation of acoustic waves as they propagate through atmospheric fluctuations. The second has to do with investigations into the applications of acoustics as a measurement tool in atmospheric research. These two areas are interrelated in gaining an in-depth understanding of each of them. It is stated in the Engineering applications of acoustics by *J. A. Kleppe*, about the acoustic sounders (SODARS). These sodars can be used to measure atmospheric structure functions and wind velocity, et cetera.

Temperature is one of the fundamental principles of science and engineering. It is found that acoustics wave propagation can be used for the measurement of temperature in gases. The main contribution of the acoustics is its capability too measure average temperatures over selected paths though a material and yield temperature profiles for industries. It acts as a non-contact type of temperature measurement. It is a new and exciting field of study that offers both quantitative and qualitative.

SUMMARY OF INSTITUTIONS UNDERTAKING ACOUSTIC ACTIVITIES

Many of the institutions visited mentioned that they were involved in various acoustics applications. The brevity of the discussions did not allow documentation of many of the technical details. Because of this lack of complete information the following discussions may be brief, but the associated tables will help to clarify where applications were mentioned.

General Physics Institute (Moscow)

Low Frequency Acoustics

Although the institute has nine departments, the WTEC is primarily concerned with the institute's work in devices for oceanographic research. While several of the departments contribute to marine related research, the majority of that work is done in the Department of Wave Phenomena. The institute's Acoustic Ocean Sounding laboratory has been using a towed fish, equipped with two transducers, in the Barents Sea to do sound path research. The frequencies employed were 100-Hz and 300-Hz and the power output used was 100-W and 300-W, respectively. In conjunction with these acoustic sources, an array consisting of 12 hydrophones is used for receiving the acoustic signals. The array, 70-meters in length, can be towed from a ship or mounted on the sea floor where it is battery powered (operating depth of 500-meters). The array has sensors to measure depth and tilt angle to compensate for these variables in signal processing. Through the use of buoys, the received data can be transmitted to a remote location up to 10-miles away.

Using this system, researchers have sent acoustic signals over a 500-km path to determine losses for both vertical and horizontal paths. This work has been used in conjunction with acoustic tomography efforts in the United States. The institute hopes to continue this work in the Arctic Basin for long-range tomography experiments. The institute also hopes to do some shallow water work with this system in the Barents Sea.

Atmosphere - Ocean Communications: An interesting application was discussed where communications between an aircraft and a submarine would be accomplished using high-powered lasers and acoustics. The aerial platform would use a very high-powered, modulated laser directed at a very small area of the ocean surface. The power output of the laser would be high enough to create mechanical surface roughness that could be sensed by the submerged platform. Through analysis of the generated surface roughness, the information transmitted would be detected.

Conversely, the submerged platform would use an upward directed very high frequency sound source to create similar roughness on the sea surface. This roughness would then be detected bycross-polarized radar. This concept has been tested from a low flying aircraft.

Andreev Acoustics Institute (Moscow)

The Andreev Acoustics Institute is a research institute and considers first principles related to acoustic applications. Although the institute does not build systems, it becomes involved in the testing and evaluation of systems after they have been developed.

The institute focuses on basic research of sound propagation in the sea, although it is now considering air acoustics as well as a number of other application areas. The institute is involved with scientific research, not prototype development. It is involved in five areas of acoustic research: (1) ocean, (2) oil and gas, (3) medical, (4) ecological, and (5) air acoustics. This is a technical institute and, as such, previously worked only on problems provided by the user community. Recently it has been given more freedom to choose its research directions, but has far less support to accomplish that research.

The following nine acoustic applications were mentioned, a few of which were discussed in some technical depth:

- Transponder system development
- Bottom referenced positioning system
- Bore hole reentry system
- Sound vision system
- Parametric sonar system
- Pulsed acoustics for pollution monitoring
- Matched field processing activities
- Communications
- Marine mammals research

Transponder System Development: The institute is interested in undersea transponders with extended durations. Some work has been undertaken that is directed at the development of transponders that would extend their endurance through the use of a sleep mode. An endurance of one year or more with a wake up mode is expected.

The institute has also been investigating the design of a multibeam receiver for obtaining accurate range and bearing determination using transponders. Investigations suggest bearing accuracies of 1°. The institute has not built these receivers, but has completed the design investigations.

Bottom Referenced Positioning System: This project uses bathymetric data to monitor the movement of slow moving objects such as oil rigs. Andreev Institute compared data acquired from multibeam sonar with previous data to obtain a motion accuracy of ±1-cm. The institute has also developed multibeam sonar of 100 1° beams.

Bore Hole Reentry System: Andreev Institute is considering using stationary arrays to monitor the positions of well drill heads. Processing will eliminate the noise associated with the drilling process and allow for range and bearing of the drilling head.

Sound Vision System: This effort is focused on medical applications. An acoustic imaging system was discussed that uses 1-MHz and a 100 x 100 array with 1° beams. The beams are electronically formed from the array data.

Parametric Sonar Systems: The institute is working on parametric sonar techniques for different applications. One such application is for oil exploration; the sediment is used to mix carriers around 300-kHz to obtain a 600-Hz difference in frequency for subbottom profiling/seismic analysis.

Pulsed Acoustics for Pollution Monitoring: The institute's scientists believe that they can obtain pollutant concentrations by analyzing received pulses that traverse along paths through small volumes of water (1 to 10 m) paths. Experiments have been conducted to develop an understanding of changes in the concentration of pollutants to 1 part per 1E8.

Matched Field Processing

The institute has been investigating matched field processing for years, and is now applying the technique to various problems. These problems include:

1. Long path acoustic current meters: the matched field techniques minimize errors introduced by the bottom and surface reverberations in shallow water channels. This increases the accuracy of measurements of fluid flow in long, shallow water channels.
2. Internal wave structure of a channel: scientists have postulated that the health of a body of water can be analyzed by understanding the flow of water entering and exiting that body.
3. Underwater acoustic holography: the institute is using optical waveguide techniques to better understand underwater sound channels.
4. Sediment measurements: Andreev's representatives indicated that a project to measure sediment properties through the use of acoustics is under consideration. By measuring the effect of an acoustic wave as it propagates through the marine sediment, various parameters can be determined.

Communications: The institute's scientists and engineers have investigated the use of this technology for communication systems. They have considered the use of filter processing techniques for underwater communications. They have opined that there was a need for long range communications at low data rates (2,000-km to 3,000-km). The same techniques can be applied to shorter ranges with correspondingly higher data rates (e.g., 20-Hz ±10 for ranges of 1,000-km to 2,000-km using a receiver with 18 bit resolution). With regard to bore head telemetry, the institute intends to use the technology for the implementation of a low data rate telemetry system from the drill-head to the surface without cables.

Marine Mammals Research: Andreev is investigating the sonar capabilities of dolphins and other marine animals, with an interest in understanding which of these sonar capabilities have application to sonar systems. Marine mammals such as the dolphin have a sonar system that is a "whole" system in this context indicates that the physiological characteristics of the animal as well as its behavior are part of the entire sonar system. Much may be learned from this investigation, it has been suggested that 5 to 100-neurons can sometimes have the equivalent processing capability of a million computers.

The institute is investigating basic issues associated with neural networks. Specifically, the question to be answered is how a group of neurons with milliseconds (msec) response times can be connected so that the group of neurons can detect msec variations.

Marine Hydrophysical Institute (Sevastopol)

Acoustic Current Meters - Special Instrumentation: The Marine Hydrophysical Institute is principally focused on the study of physical oceanography. Scientists at the institute have a substantial design, development, and manufacturing capability to support the development of instrumentation required for their activities.

The institute has developed a number of acoustic current meters. It has focused on acoustic current meters that measure velocity components at a point rather than utilizing the Doppler system concept. No other unique applications of acoustic technology were reported; however, studies of other application may be underway.

Shirshov Institute (Moscow)

The Shirshov Institute is involved with the development of platform and instrumentation systems needed to support its oceanographic research. Since there was limited availability of Western equipment, the institute's scientists and engineers were forced to develop their own instruments. While this activity was driven by necessity, it also helped to stimulate the development of some unique devices. The applications mentioned were:

- Sonar information processing
- Transducer elements for side scan sonar and acoustic imaging
- Hydroacoustic beacon/transponder for divers/mammals
- Geophysical towed arrays

Sonar Information Processing: the focus of this investigation is sonar information processing that is related to side scan sonar imagery.

Transducer Elements for Side Scan Sonar and Acoustic Imaging: the focus is the development of transducers that are rated for 6,000-m and are used in side scan sonar and imaging systems.

Hydroacoustic Beacon/Transponder: this effort focused on the development of a beacon/transponder system for attachment to divers and marine mammals. In both cases, physiological and location data can be sent back to a remote station. It was suggested that this system could be used to control the activities of marine mammals via long distance communications.

Geophysical Towed Arrays: Mr. Merklin discussed his development of a smaller, lower-cost geophysical seismic system. Pointing out that existing 3-D systems are large and expensive, his goal is to achieve similar results with much less complexity by developing a 5-km towed array using sensors that are only 20 to 25-mm in diameter. A microjet transmitter would transmit a complex broadband signal as a source for seismic analysis of the returning signals.

Additional Information: additional information can be obtained from a publication developed by the Office of Naval Research, European Office (NAVSO P-3678). This publication cites acoustic applications under investigation at the Laboratory of Acoustic Noise and Sound Fluctuations and the Acoustic Wave Propagation Laboratory of the institute. These include free-floating acoustic recording capsules, bottom tomography, various arrays, and a portable acoustic positioning system with baseline distances in the 20 to 25-km range.

Institute of Applied Physics (Nizhny Novgorod)

Discussions during the WTEC team's visit focused on the Department of Hydrophysics and Hydroacoustics for work related to acoustic applications, where most of this institute's ocean-related work takes place. Although little technical detail was discussed, several projects were mentioned, including:

- Remote diagnostics of ocean phenomena
- Submarine location using acoustic and nonacoustic means
- Low frequency acoustics in the sea
- Phased arrays in sound transmission and reception
- Signal processing
- Physical and mathematical modeling of the oceans
- Environmental monitoring
- Acoustic Doppler current profiler, 3 beams; 30° or 120°
- Mobile linear array

Low Frequency Sources: one example of work on low frequency sources was the testing of a compact electromagnetic monopole source in conjunction with the Woods Hole Oceanographic Institute (published in WHOI-93-09). The titanium source, developed at IAP RAS, has a mass of 123-kg and a diameter of .54-m. The system has a center frequency of 225-Hz, a bandwidth of about 50-Hz, an associated pulse resolution of about 200-msec, and a source level of 198-Db referenced at a pressure of 1-mPa at 1-meter, with an efficiency of about 50 percent. This source is being considered for use in monitoring the ocean to understand more about global ocean processes and their impact on the world's climate.

Mobile Linear Array: this 200-meter long mobile linear array consists of 64 hydrophones spaced 3-meters apart (300-meter operating depth). The system is capable of making very accurate acoustic spectrum measurements from 20 to 300-Hz. The upper range can be extended to 2,000-Hz. Included with this system, which is available for sale at $20,000, is signal processing software, which otherwise costs an additional $12,500.

Acoustic Doppler Current Profiler: this instrument is a three-beam (30° beams oriented 30° off vertical in 120° azimuthal increments), 220-kHz system for operation in water depths to 400-meters (200 to 300-meters for current profiling, and 300 to 400-meters for ship velocity measurements). The system is configured with an IBM/AT for processing. It is believed to be superior to the RD Instruments system.

Scientific Research Institute of Computer Complexes (NIIVK)

NIIVK is the group at the institute responsible for designing computer hardware and systems software. In accomplishing this task, NIIVK scientists developed algorithms for sonar systems. Much of this work was originally classified (and some remains so) but is now unclassified. Efforts are underway to commercialize several acoustic applications that have evolved from the work at NIIVK. The following describes some of those concepts.

Fish Monitoring Sonar System: this system is designed for low-tonnage vessels fishing in any open ocean areas. It is aimed at detecting pelagic and bottom fish shoals to determine their location while the vessel is operating at full speed in seas up to a sea state of 4. The system is used in low-tonnage vessels for object detection (fish, crustaceans, mollusks) in active and/or passive (on receiving bioacoustic signals) sonar mode.

The unique feature of the system is its use in a passive sonar mode, which assists in the detection and classification of living resources on or in the bottom layer, which is a favorite location of crustaceans and mollusks. The Fish Monitoring Sonar System includes a receiving-transmitting transducer (antenna); a signal processor; and displaying, recording, and control devices. The use of a standard recorder and a standard display is possible, as well. Receiving-transmitting and control devices should be installed in a pilot house. The sonar system range is nominally 15-km, but depends on sea depth, sound speed dependence, bottom and surface acoustic parameters, and equivalent radius of a fish shoal.

Compact Sonar System for the Nearest Water Area Viewing: this compact sonar system is designed for an underwater apparatus used in shelf zones for applications such as exploration of mineral deposits, laying cable, surveying platform sites, and investigating ice covers. General system specifications are given in Table .2.

This parametric sonar system has a transmitting array of 0.2 square meters in the angular sector. A parallel-sequential spatial view is obtained by the system.

Table. 3.5.2

General System Specifications -- Nearest Water Area Viewing

Range	0.1 to 2 km
View Sector in azimuth in elevation	 45 15
Distance Resolution	0.2 m
Angular Resolution	1 to 3
Antenna Square	0.2 to 0.6 m^2
Equipment Volume	0.2 to 0.6 m^3
Submergence Depth	up to 500 m
Power Consumption	0.5 kW

The receiving array (0.6 square meters) receives a noise and valid signal mixture. The amplified, filtered, and digitized signals are sent to the computing facilities. Signal processing includes the following:

- Multibeam forming in the spectral region
- Reverberation noise suppression
- Matched filtration
- Signal detection and signal parameters measurement
- Primary signal classification
- Data preparation for displaying

- Processing results arching

The processing results are displayed. An operator analyzes the image and, taking into account primary classification data, identifies the object under observation.

Design specifications of this system are available. The main design concepts have been analyzed, simulated, and tested in natural conditions, and the array breadboarding has been accomplished. Proposals for cooperation with foreign participants are being sought.

Multiship Fish Monitoring Sonar System: this compact system is designed for fish shoals search and classification in the shelf zone and in the open ocean. General system specifications are given in Table .3.

The pseudo random signal transmitting antenna is towed by the most forward fishing vessel. The receiving array is towed by one or two fishing ships, moving parallel with the major vessel. The arrays receive a noise and valid signal mixture. These signals are amplified, filtered, digitized, and sent to the computing facility. Signal processing includes:

Table. 3.5.3

General System Specifications -- Multiship Fish Monitoring

Range in the shelf zone in the ocean	 5 to 10 km 3 to 5 km
Shoal Detection Accuracy distance accuracy angle accuracy	 5% of a distance 5°
Classification Probability	0.8 to 0.9

- Forming multibeam directivity diagram in the spectral region
- Filtration, matched with moving underwater objects
- Measuring signal detection and signal parameters
- Classifying initial signals
- Preparing data for display
- Filing processing results

The processing results are displayed. An operator analyzes the image and, taking into account initial classification data, identifies the object under observation. Data concerning new objects are then loaded into the classification database.

Scientific analysis of detection methods and underwater moving objects classification are available. Proposals for cooperation are being sought.

Sonar System for Beam Structure Parameters of Undersea Acoustic Fields: this system is aimed at acquiring parameters of undersea acoustic fields and comparing empirical data with calculated parameters. The system can measure the following:

- Propagation beams
- Beams focusing factors
- Angles of arrival in the vertical and horizontal planes
- Time delays between beams
- Correlation factors between beams
- Spatial intervals of beams coherence in the vertical and horizontal planes
- Time intervals of beams coherence
- Bottom and surface reflection factors
- The ocean noise spectrum and spatial characteristics

General system specifications are given in Table 3.4. The antenna, installed at the transmitting ship, transmits a pseudorandom signal. The array at the receiving ship can be placed in the vertical or horizontal position. It receives a noise and valid signal mixture. Amplified, filtered, and digitized signals are sent to the computing facilities. The computer evaluates the beam structure parameters of sea acoustic fields. The use of special algorithms provides beam super resolution. Computer system software includes beam structure evaluation of acoustic fields and the comparison of theoretical and experimental results.

In order to make measurements more accurate, the receiving array is automatically calibrated at regular intervals. Processing results are displayed and loaded into a database. This measurement method has been experimentally verified in the Atlantic Ocean. Proposals for cooperation are being sought.

Table. 3.5.4

General System Specifications -- Beam Structure Parameters

Antenna Length	36 m
Frequency Band	1 to 6 kHz
Number of Resolution Beam Clusters	up to 16
Number of Resolution Beams in a Cluster	up to 3
Angle of Arrival Measurement Accuracy	1 to 3 minutes
Time Delay Measurement Accuracy	10^{-4} sec
Focusing Factors Measurement Accuracy	5%

Oceanpribor (St. Petersburg)

Oceanpribor is the largest Russian company specializing in the design and manufacture of hydroacoustic systems. The company has developed and is selling transponders and transducers as well as hydroacoustic systems for various applications under the trademark "Korvet." Hence the company is sometimes known as Korvet Oceanpribor. Table 3.5 summarizes some of its offerings.

Bureau of Oceanological Engineering (Moscow)

The bureau's primary function is to design, build, and test samplers, sensors, and instrumentation for oceanographic research. Its activities in acoustic applications seem consistent with the types of instruments commonly found in the ocean community. The following applications/acoustic instruments were mentioned:

- Acoustic releases
- Long and short baseline navigation systems
- Transponders for the navigation systems
- Communications between submersibles and surface vessels

Geoton Company (Dubna)

Acoustic Data Acquisition System: Geoton (in existence for about two years) presented a multichannel seismic system to explore for oil and gas. The unique feature of the Geoton system is its multichannel capability for data acquisition and processing. Up to 10,000 channels are possible in the system, which can enable three-dimensional views and greater accuracy for location of test drilling sites. Geoton claims that this will reduce the number of test wells by one-third. With the Geoton system in place it is also possible to estimate undepleted reserves in productive oil and gas fields.

Table . 3.5.5

Oceanpribor's Transponders, Antennae and Systems

SYSTEM TYPE	FREQUENCY	ENDURANCE	DEPTH	COMMENTS
Transponder	8 - 30 kHz	280 hrs - 120 days; 3 yrs	1,000 - 6,000 m	family of transponders
Transponder	14 - 19.5 kHz int. 8 - 13.5 kHz res.	10 days - 180 days; 3 yrs	6,000 m	various reply strategies
Transponder	7.75 - 12.25 kHz int. 25/35 kHz res.	2 yrs - 3 yrs	1,000 m	
Transponder	21.55 - 26.46 kHz fixed freq. int. 27.17 - 32.47 kHz fixed freq. res.	2 yrs	1,000 m	
Transponder	38.5 or 39.5 kHz fixed freq. int. 37.5 kHz fixed freq. int.	2 yrs	1,000 m	
Transceiver array	10 - 20 kHz Xmit 7 - 14 kHz Rcvr			30, 45, 90 deg. beams
Transceiver array	70 kHz		unlimited	0.75 deg. beams "cosec"
Transceiver array	80 kHz		6,000 m	3.5 deg. beams "cosec"
Transceiver array	400 kHz		unlimited	1 deg. sector
Transmitting array	14 - 20 kHz 3 - 7 kHz		1500 m	7 deg. beam 9-25 min. beam (prototype)
Hydrophones	various		100 - 1500 m	
Multipurpose scanning sonar	80 kHz		6,000 m	7.5, 15, 30 deg.
Hydroacoustic telephone communication systems	30 - 40 kHz 82 - 85 kHz	10,000 hrs 10 hrs	350 m 60 m	range 2,000 m range 250 m
Digital communication system over hydroacoustic channel	Multibeam channel			2,000; 500 bit/s range up to 15 km
Ship positioning system	7 - 12 kHz int. 25 or 35 kHz reply		30 - 800 m 50 - 6000 m	12 km range (or more)
Sonar Doppler log	255 kHz		6000 m	4 x 3.5 deg.

Geoton has fabricated components for its system and tested them in the laboratory. Systems have been developed around the TMS 320 processor using algorithms developed solely in Russia, since the company has had no access to the computer technology of the West. The Institute of Oil and Gas has deployed and tested a 12-channel system with good results. Although Geoton is not a manufacturer, it will form partnerships with other Russian companies to produce the system. Geoton representatives believe they are well positioned to serve companies that will be conducting oil and gas exploration in the fields of Siberia, and are looking for clients with that same interest.

ROS Company (Dubna)

Passive Sonar System (minisosus): the ROS Company has developed and is ready for sale: a seabed passive sonar system. This low-frequency system operates from less than 1 Hz up to 5 kHz, and has a sensitivity of 250 microvolt/Pa.

The wet part of the system consisted of multiple hydrophone arrays; each array is in a straight line with multiple arrays ganged onto an underwater data transmission line. The arrays might have 30 or 80 hydrophones. From four to eight arrays would make up the underwater systems. Analog to digital signal conversion was provided at each hydrophone, and electronic to optical signal conversion occurred in a regenerator at the array level to enable fiber optic transmission to the shore station.

The dry part of the system consisted of a remote-controlled power supply and an acoustic data analysis and display system that used an 80486 microcomputer. Very efficient data sampling, and compression and analysis algorithms were claimed for the system, which together with TMS 320 S-30 chips for each four arrays enabled effective and timely processing with a 486 microcomputer. Frequency, bearing, time, and target location (depending on array layout) could be displayed for up to five simultaneous targets per display. A database for classification of shipping targets are available from ROS. Larger projection displays can be incorporated if desired. The wet system can be retrieved and redeployed. The dry system is compact enough to reside in a mobile van.

Peleng Company (Dubna)

Low Frequency Acoustic Sources: the Peleng Company specializes in high power, low frequency (below 1,000-Hz) acoustic emitters. Mr. Polevik is a senior scientist there with many years of experience in emitter design, and holds approximately 80 patents for acoustic devices. He discussed the design of sparker, boomer, electrodynamic, and hydraulic-type emitters. Finally, he discussed the characteristics of a patented cylindrical emitter, created especially for use in seismic operations.

The problem of more durable electrodes in the sparker device has been solved by encapsulating them in a special liquid in which the high powered electric discharge takes place. The power in a single pulse from this large device, which is 1.2-meters by 0.6-meter and weighs 300-kg, is 5-kJ. This power is hydraulically transmitted through the encapsulation to the surrounding sea. The operational depth of the device is up to 200-metere.

High Powered Boomer-Type Induction Pulsing Emitter: a high powered boomer-type induction pulsing emitter with a tunable frequency response was described. The device was tunable to provide maximum amplitude in the low frequencies -- 50 to 700-Hz. It was claimed to be the first such design available for deep water use, that is, up to 300-meters.

Pulse Resonant Transmitter with High Frequency Response: a working model of a new pulse resonant transmitter with high frequency response has been developed. The transmitter has a flat characteristic curve in the 10 to 300-Hz range through the use of reactive compensation, and has output power in the 3-kJ range. The transmitter is electrohydraulic; it is totally electric at low power levels and can be totally hydraulic at high power levels.

Low Frequency Active Array: a developmental concept was discussed for a low frequency active array of cylindrical shapes that may be used for exploring for oil and gas fields. The array would be arranged to fit down into oil and gas well casing and would operate in the 50 to 100-Hz range with positioning controls to produce a directed beam pattern along a horizontal plane. The total system would also include a multichannel receiver array.

INFRAD Company (Dubna)

Fish School Detection Using a Passive Sonar System - ARGUS System: a senior scientist from INFRAD described the ARGUS system, which is being developed in partnership with other companies in the Dubna region. The ARGUS system proposes using sonar emission tomography to detect fish shoals, currents and underwater waves, and sediment fallout rates. The proposed system would be purely passive and would have application to a maximum depth of 1,000-meters, with a monitoring base line of 150-meters that lies up to 200-km offshore. The pattern of surface noise would be analyzed through array processing and fish, currents, or sediment, and could be characterized as to depth, density, and school size of fish. The processing by each array would require the characteristics of the conditions in situ. The spokesperson for INFRAD explained that for about one year, there had been basic work exploring the fine structure of hydroacoustic fields to support the concept of sonar tomography, but as yet there had been no funding to support experiments.

Heriot-Watt University (Aberdeen)

The discussions at Heriot-Watt University focused on two groups involved with research directly related to undersea systems. The Ocean Systems Laboratory, headed by Professor George Russell, is investigating several different areas, three of which focus on sonar applications. The second group, headed by Dr. L.M. Linnett, was investigating sonar signal processing. The following topics were discussed:

- Multisensor fusion
- Subsea communications
- Digitally focused sonar system
- Object detection
- Pipeline inspection
- Seabed characteristics
- Sonar data compression
- Sonar simulation

Multisensor Fusion: this investigation studied techniques for sensing three-dimensional environments in which subsea robotics activities take place. The techniques would provide the precise positional information required by combining signals from optical sensors and acoustic sensors. It is anticipated that increased accuracies would be realized.

Subsea Communications: these studies investigate mathematical models of underwater acoustic propagation channels and the validation of these models through field demonstrations. The purpose of these efforts is to provide design information for high data rate communications for autonomous underwater vehicles (AUV).

Digitally Focused Sonar System*:* this project seeks to develop methods of creating high definition images by the digital processing of signals from sonar arrays, with application to the detailed survey of seabed features, texture classification, object detection by surface vessels and underwater vehicles, obstacle avoidance, and navigation of AUVs.

Object Detection: the group's years of work on object detection has advanced to a stage where excellent detection rates have been achieved for many different seabed types. The work is now aimed at assessing the probability of detection against different backgrounds.

Pipeline Inspection: a system has been developed for inspecting subsea pipelines using side scan sonar techniques to detect spans (unsupported sections of a pipe). A system that performs real-time processing of the data has been successfully produced.

Seabed Characterization: this work has reached the stage where excellent characterization of complex seabeds from side scan sonar records has been achieved. The present aim is towards a database of seabed types covering most areas of the seabed. With the increase in data rates from sonar equipment, the capability to accurately analyze data quickly is essential. To this end, a system has been developed for performing on-line segmentation of seabed types. This has application in hydrography where it is possible to perform seabed comparison over very short time scales. This could be of major importance during times of conflict.

Sonar Data Compression: with the increase in resolution of modern sonars, gigabytes of data are now being gathered in side scan surveys. Techniques have been developed that are capable of compressing the information by many orders of magnitude. This has obvious benefits for the storage, manipulation, and transmission of such data. Work is continuing on techniques for real-time handling of acoustic data.

Sonar Simulation: the group is developing mathematical and graphical techniques for synthesizing side scan data. The aim is to develop a system to allow the study of the sonar process, which will aid analysis and detection work.

Marine Technology Directorate Ltd. (United Kingdom)

The Marine Technology Directorate (MTD) is a United Kingdom-based association with international membership. The members have significant interests and capabilities in ocean-related technologies and come from industry, government, research establishments, academic institutions, the United Kingdom's Science and Engineering Research Council, and the Royal Academy of Engineering.

MTD funds research programs that relate to undersea vehicle technology. One such research program, the Technology for Unmanned Underwater Vehicles (TUUV) program, covers a broad spectrum of technology problems in six main areas: sensing, control, communication, navigation, propulsion, and analysis. Three of those projects reflect types of activities related to acoustic applications in the undersea environment. MTD advances research and development through its funding of marine research. MTD also encourages communication in the marine community by organizing discussions with companies whose interests relate to the objectives of the WTEC study. A description of three TUUV projects funded by MTD follows:

Techniques for Processing Side Scan Sonar Data from Large Data Sets (Heriot-Watt University): in recent years, there has been an increase in the demand for high quality side scan sonar data for mapping sediments on the seafloor. Coupled with this demand has been increasingly sophisticated sonar equipment capable of obtaining high resolution images of the seafloor. These factors have led to an abundance of data that must be examined by trained personnel in a subjective and time-consuming process. Techniques must be developed to more fully automate this process.

A New Underwater Vision System (Strathclyde University): the goal of this project is to investigate a new vision system for working underwater. It combines the complementary characteristics of stereo optics with three-dimensional acoustic imaging. A 2-D matrix ultrasonic array, fixed relative to a pair of underwater cameras operating in stereo mode, will generate spatial and depth information to a target. This data will then be used to update and optimize a stereo matching algorithm to provide accurate 3-D optical vision. The objectives of the project are: (1) to merge acoustic data with 3-D optical data; (2) to design and evaluate a 2-D matrix ultrasonic array; (3) to create and implement stereo matching algorithms by fusing acoustic and optical data; and (4) to evaluate a prototype system.

High Data Rate Subsea Acoustic Communications for UUVs (Newcastle University): the goal of this project is to better understand the potential for using acoustics to achieve 20-kbits/sec data transmission in shallow water environments. The objectives of this effort are: (1) to determine the fundamental limitations relating to the use of phase shift keying (PSK), beamforming, and adaptive equalization in the subsea environment; (2) to develop a half-duplex acoustic telemetry link using simultaneous beamforming at the transmitter and receiver; and (3) to demonstrate the practicality of high data rate acoustic communications systems operating in real conditions.

Tritech International Ltd. (Aberdeen)

Tritech produces a range of advanced, high performance, and compact scanning sonar heads, all of which can be operated from the SCU-3 Multitasking Surface Control Unit. The heads are available in three different frequencies to satisfy the majority of underwater requirements. The ST 325 long range scanning sonar is used throughout the world. It is an all-around sonar with a 200-m range capability. It is generally used for obstacle avoidance and navigation on small and large vehicles. The ST 525 high resolution, imaging sonar combines long range (100-meters) with high resolution making it suitable for most ROV applications, including target acquisition and debris survey. The ST 725 very high resolution sonar is a high resolution, mid-range (50-meters) imaging sonar used where higher resolution images are needed as contrasted to long operation sonar types.

The scanning heads for these sonar systems are available in three different configurations (vertical, horizontal, and big top) to allow installation in the available space. The big top version has a larger transducer than the standard vertical and horizontal heads. This design produces a narrower and more concentrated sonar beam, resulting in higher angular resolution beam patterns.

Table. 3.5.6

Specifications of Tritech Sonars

SPECIFICATIONS	ST 325	ST 526	ST 725
Frequency	325 kHz	525 kHz	
Bandwidth, normal	4.5 x 24	4.5 x 24	2 x 24
Beamwidth, Big Top	2.5 x 24	1.2 x 24	N/A
Maximum Range	200 m	100 m	50 m
Pulse width	60 - 1,000 µsec	60 - 1,000 µsec	60 - 1,000 µsec
Scan rate	8 - 40 sec	8 - 40 sec	8 - 40 sec
Depth rating	3,000 m	3,000 m	3,000 m

The sonar heads share a common power supply requirement and data communication protocol that enable the connection of multiple devices, including sonar, profilers, and altimeters, to the SCU-3 via a single twisted pair.

The SCU-3 is a powerful yet simple to operate multitasking acoustic processor. In addition to controlling ST sonars, it also operates Tritech ST 1000 scanning profilers, displays real-time video, and shows information from other sensors, such as a TSS 340 Pipetracker and eastings and northings from a navigation computer, all on the same monitor simultaneously. Data may be logged to and replayed from disk.

Images may be taken from SCU-3 and entered into desktop publishing packages to assist in creating post-operation reports.

Reson Systems UK (Aberdeen)

The SEABAT 9001 system is a multibeam sonar system that carries out profiling operations. It consists of a low weight (5-kg in water) multibeam sonar head, a 19-inch rack mounted processor, a high resolution monitor, and a track-ball with which to control the system (all functions are menu driven).

The SEABAT 9001 transmits a 90° x 1.5° fan beam consisting of sixty 455-kHz individual beams (1.5° x 1.5°) in one single pulse. All the beams are formed using a curved face transducer that minimizes background noise.

Because a single pulse is transmitted, undistorted profiles are generated, accurately portraying even the most complex sea bed features. Also, due to the single transmission pulse, the full 90° profile is updated at 30 times per second at ranges of 25-meters or less, and reducing to 7 times per second at a distance of 100-meters.

The SEABAT 9001 exports the X/Z coordinates as a data stream twice per second to be integrated with roll, heave, pitch, and heading sensor information via a data acquisition program to provide an XYZ data stream. This data stream is combined with the positioning information supplied via the navigation program and passed through a digital terrain modeling program to provide the specified chart(s).

The SEABAT 6012 is a 455-kHz electronically scanning minisonar. It was especially designed as a principal ROV sensor for mine warfare. It is a 90° forward-looking sonar used for detection, relocation, and classification of mine-like objects located on the seabed or in the mid-water column.

The SEABAT 6012 functions in real-time with a visual window of 90° horizontally and 15° vertically. This, in effect, is similar to a wide angle camera view. Because the SEABAT displays static and moving objects dynamically in real-time, the sonar head can be set on a pan and tilt mounted, as you would a video camera, to follow an area of interest while maintaining orientation. This is particularly useful when monitoring installation or positioning procedures in visibility that precludes the use of video.

The 6012 has a maximum usable range of 200-meters and a minimum set range of 2.5-meters. The speed of update is controlled by the range selected and is dependent on the speed of sound through water. For example, at ranges from 2.5 to 25-meters, the update is 30 times per second. The image displayed is optically correct, with the objects viewed appearing without dimensional distortion. This remains the case regardless of the speed of movement of the supporting platform or the object being viewed.

Marconi UDI (Aberdeen)

Marconi UDI [now Fugro UDI Limited] is a relatively small company focused on the development and application of sonar systems. The company has a strong focus on the development of acoustic transducers, and has expanded that focus into different projects. Marconi has a modular building block concept where the company packages standard blocks of transducers into large arrays. The following summaries describe some of the systems discussed.

Sonavision 4000: Sonavision 4000 is the first commercial high frequency scanning sonar to use UDI's newly developed composite array technology. The use of these arrays results in a wider bandwidth and much greater efficiency in the conversion of electrical energy into mechanical energy.

The Sonavision 4000 transmitter and receiver electronics are fully tunable via software from 150-kHz to 1.5-MHz. Therefore various beam angles and frequencies are available, that is, 1-MHz profile and 2,000-kHz long range search. See Table .7 for specifications.

In one application, the standard Sonavision 4000 sonar product was modified to take a 1.2° 500-kHz sonar array. The computer graphics card in the display system was modified to store up to 10 sonar pictures and the OS9-based control software was adjusted accordingly. Software was also supplied for personal computer control of the sonar system, enabling the operator to store sonar images to disc.

Connectivity Piezoelectric Materials for High Frequency Sonar: UDI and Strathclyde University have spent three years developing new materials for sonar applications. In brief, the material consists of piezoelectric ceramic pillars embedded in a polymer matrix. In general, the combination of long, tall ceramic pillars and polymer materials enhances the electromechanical conversion efficiency and reduces the acoustic impedance to provide a better match to water. The results have enabled phased arrays to be manufactured at a fraction of their price, and for special sonar transducers to be supplied at little additional cost to clients.

Table. 3.5.7

Specifications of Sonavision 4000 at 500 kHz

Transmit	27 vertical x 2.1 horizontal
Receive	27 vertical x 3.0 horizontal
M.D.S.	72 db
Source Level	210 db re 1 micropascal at 1 m
Pulse Length	100 msec
Bandwidth	10 kHz
Scan Rates (Menu Selectable)	Slow, normal, fast, super fast

Cavitation Cleaning Sonar: UDI built technical demonstrator sonar consisting of a 400-mm diameter multi-ring 270-element phased array, and racks of 45-watt power amplifiers. The system was designed to produce a focused beam capable of cavitating a small volume of water. The cavitation effect can be used to remove rust from metals. Investigations are underway into its capabilities for removing marine growth.

Mirror Sonar: the company participated in the design and manufacture of the arrays and subsea electronics for a low cost mirror sonar. High frequency multi-element sonar receivera and transmit arrays were designed and built into a focused acoustic mirror housing. Electronics from UDI's modular sonar designs were incorporated to provide a 24-channel sonar system.

Modular Arrays: UDI has developed a modular construction technique for a sonar phased array. Using this technique, 8 array modules of 16 elements each were mounted onto a frame, producing a 128 element array. Electronic pods containing power amplifiers and preamplifiers were also delivered. Electronics costs were kept to a minimum by using UDI standard sonar building blocks that use surface mount devices.

Marconi Underwater Systems (Waterlooville)

In conjunction with its product development, Marconi Underwater Systems has developed acoustic systems. During the visit of the WTEC team, a few of those applications were discussed briefly, as summarized below.

Communication between Divers and Between Diver and Surface: a sealed diver electronic module (DEM) has been designed for use to a depth of 100-meters. Divers using gloves can carry out simple battery changes. Communication is achieved using high frequency acoustic waves transmitted through water between acoustic transducers attached to the DEMs. Each DEM uses a single sideband, a suppressed carrier, transmitters, and receivers.

A two-way simplex communication is available; each transmission is preceded by a short tone-burst. The operation of the press-to-talk (PTT) switch causes the changeover from receive to transmit. To enable diver-to-surface communication, an adaptive headset is used for the surface operator, while the diver uses bone conduction earphones and microphones.

A minimum effective distance of 1-km can be achieved when the DEM is selected for long range applications. A facility exists to reduce the effective range to short range (less than 100-meters), depending on prevailing propagation conditions for use in complex missions. Any number of divers can be in contact with the controlling surface station.

A Hull Mounted High Definition Scanning Sonar for Surveying Inshore Coastal Waters: the transmitting and receiving arrays assembled within the sonar head are mounted beneath the vessel. The scanned sector can be depressed to any angle from the horizontal and can be rotated to any position in azimuth, in either the vertical or horizontal mode.

The sonar head is mounted on a dynamic, stable platform that relates the beam to a fixed spatial reference independent of roll, pitch, and yaw by the vessel. The 60° insonified sector is scanned electronically by a very narrow beam to generate a high definition video image. Each echoed pulse represents angle and range data for processing by the computer. The received echoes are digitized and subjected to modern image processing techniques. These enhance the composite video and eliminate flicker. Performance has been demonstrated up to speeds of 10-kt and a sea state of 4.

The Mark II Hydrosearch outputs standard CCIR TV format. This permits the use of a wide range of devices, such as TV monitors, line scan recorders, video recorders, and output printers.

Bathyscan Swath Echo Sounding System: Bathyscan is a 100/300-kHz swath echo sounder based on the principle of acoustic interferometry. In the 100-kHz mode the system will operate in continental shelf water depths and can map a swath up to 500-meters wide, while at 300-kHz it offers high resolution surveys in rivers, harbors, and estuaries.

Advanced Models of Sound Propagation in the Ocean: Marconi Underwater Systems is engaged in research on the propagation of sound in the oceans in order to further develop the company's knowledge of the complex underwater environment. Computer models of sound propagation play an important part in this research and allow the user to predict the distribution of sound intensity given prior knowledge of the physical properties of the ocean, such as its sound speed profile.

IFREMER (Toulon, France)

IFREMER, a French government agency with scientific, industrial, and commercial roles, directs, funds, and promotes ocean research and development. The agency often develops system concepts, and works with industry to build the system and evaluate its operation. The Toulon facility is focused on the operation of many of the developed systems. The Brest facility, however, has established an acoustics development laboratory. The following applications were mentioned, although few details were available: (1) acoustic data transmission; (2) acoustic determination of seabed characteristics; (3) development of very low frequency transducers; and (4) array processing (acoustic tomography).

SUMMARY OF SYSTEMS AND APPLICATIONS

Table 3.5.8 lists the organizations working on or developing specific acoustic systems. Table 3.5.9 also summarizes the specific application areas considered at the institutes.

Trends

Ecological and environmental applications are a primary area under consideration for applying existing and new technology. Current awareness and concern for environmental issues in Russia and Ukraine are apparent. Water quality, noise pollution, acceptable standards for the impact of technology and industry on the environment, and a number of other issues are areas where existing technology can be applied.

Low Cost Systems: it is clear that the cost of technology is a factor to be considered in future applications. The low cost sonar systems offered by Tritech are attractive. The technology has advanced to a point where new techniques and hardware promise significant capability at a lower cost than has been the case for existing sonar systems and other acoustic equipment. In Russia and Ukraine there is a sensitivity to price and its importance to Western markets. In Europe, the Marconi *ODAS* system development efforts focus on a low price tag.

Long Endurance: As is shown in the previous tables, some transponder systems have quoted endurances of multiple years. Projects are directed at increasing the endurance of other autonomous instrumentation. In Europe, the Autosub program seeks transits of 7,000-km; the French have focused some of their work on long range systems. Endurance is an important design consideration for acoustic transponders and other instrumentation under development.

Table. 3.5.8
A Summary of Application Focus and User Community

SYSTEM	USES / USER COMMUNITY	ORGANIZATIONS INVOLVED
Acoustic Arrays	Oil and Gas Science Maritime	Shir, IAP, Kor*
Transponders	Instrumentation Various Applications	And, Shir, Kor, BuO
Transducers	Instrumentation Various Applications	Shir, Kor, UDI, IFRE, Pel, (Kiev?)
Sonar Imaging Systems	Oil and Gas Medical Seabed Characterization	And, NII, Kor, HW, TriT, Res, UDI, Marc
Communication Systems	Maritime Oil and Gas	GPI, And, Kor, HW, Marc, IFRE
Position / Navigation	Maritime	And, Shir, St.PU, BuO, HW, Kor
Parametric Sonar	Oil and Gas Science	And
Acoustic Releases	Science	Shir, BuO
Acoustic Current Meters	Oceanographic Community	MHI, Kor
ADCP Systems	Science - Oceanographic Research Maritime	IAP

* Kor = Oceanpribor (Korvet Oceanpribor)

Higher Resolution: several institutions focused on higher resolution acoustic information. In Europe, interest in higher resolution sonar imaging systems is great. At Strathclyde University, MTD is funding an effort to develop more accurate position data for undersea tasks. In Russia and Ukraine, the term "super resolution" acoustic data were emphasized. Improvements to existing technology are clearly focused on increasing the resolution of acoustic systems either with new hardware techniques or with advanced sonar signal processing and high-speed algorithms.

Efficient Sonar Signal Processing: computer hardware available to researchers in Russia and Ukraine has been limited. Researchers are focusing on better defining the problem and developing new methods to process the acoustic data. These new methods appear to be superior to those found in the United States and other western countries.

Table.3.5.9

A Summary of Organizations Involved in System Design

APPLICATION AREAS	USER FOCUS	ORGANIZATIONS INVOLVED
Array Processing	Fisheries Government Maritime Science	IAP, NII, Ros, INFRAD, GPI, Kor
Environmental Monitoring	Environment	And, IAP
Ocean Acoustics Studies	Environment	And, Shir, IAP, NII, GPI, Kor
Matched Field Processing	Various	And, (others?)
Seismic Data Acquisition	Oil and Gas	GEO
Sonar Simulation	Oil and Gas Maritime Science	Shir, HW, Kor
Holography	Materials Sediment Class Communications	And, GPI
Tomography	Science	And, IFRE, GPI, Shir
Sonar Image Processing	Various	And, HW, Shir, Kor
Marine Mammals Research	Research	And, Shir
Physical Oceanography	Science	MHI
Sediment Analysis	Environment Oil and Gas Maritime	And, IFRE, Kor

SUMMARY AND CONCLUSIONS

In summary, there are a number of applications of acoustic technology that are both exciting to consider and important to advancing the state of the art for this field. These applications are at a state of development where prototypes are being designed and fabricated, and in some cases, commercial products are now available.

Noise Source Identification (NSI): is an important method for optimizing/controling the noise emission from mechanical and electromechanical products. The goal of NSI is to identify the sources of noise emanating from an object in terms of its position, frequency content and sound power. Direct measurement methods like sound pressure mapping and sound intensity mapping are based on mapping the variables that were measured. Indirect methods like STSF and Beamforming rely on sound field propagation models to calculate sound field parameters in positions that are not directly measured. This not only provides more freedom in choosing where to measure but can also provide a more complete understanding of the behavior of the sound field. Some methods support measurements of typical transients like run-ups and impact type noises. For analysis on internal combustion engines it is often relevant to also use these technologies to analyze noise emission as a function of the engine cycle. Since most methods involve measuring a large number of points, the measurement is most efficiently performed using an automated transducer positioning (robot) system and/or a microphone array.

3.5.10 Acoustic Imaging – Beam-forming

Beamforming is a method of mapping noise sources by differentiating sound levels based upon the direction from which they originate. The method can be accomplished in a short period of time and allows for a full map to be calculated from a single-shot measurement. It also can be used at high frequencies.

The innovative Brüel & Kjær wheel arrays can be used with PULSE Beamforming to produce acoustically optimal results while maintaining maximum ease of use and handling. PULSE Beamforming software is centered around an easy-to-understand tree structure where all measurements and calculations are represented. From there, drag-and-drop functionality allows you to plot results in both 2 and 3-Dimensions. In addition, results can be superimposed on an image of the measured object.

Uses

PULSE Beam-forming has the following primary uses:

- Noise-source location,
- Mapping of noise radiated from medium- to large-sized objects such as vehicles, components and construction equipment,
- Remote measurement in environments where it is difficult or dangerous to take measurements close to the source. There are several examples of environments of this types such as a wind-tunnel,

- Higher frequency mapping that exceeds the capabilities of standard noise source location methods.

Acoustic Material Testing

PULSE Acoustic Material Testing Type 7758 implements the core functionality of obtaining absorptionand reflection coefficients, impedance and admittance ratio of acoustic materials. In addition, it has measurement, post-processing, display and report facilities.

Elements

A complete Acoustic Material Testing System consists of a PULSE system with Acoustic Material Testing Program Type 7758, Two-microphone Impedance Measurement Tube Type 4206, and Power Amplifier Type 2716 C.

Acoustic Material Testing has several configurations available for measurement of the absorption coefficient according to ISO 10534-2 and ASTM E1050. Transmission Loss measurement is also available as an option.

- Standard Material Testing with Small and Large Tubes (ISO 10534-2)
- Material Testing with Mid-size Tube (ASTM E1050)

Applications of acoustic arrays

Sonar technology and phased array technology have been merged and used in tandem with very impressive results (Lombardo et.al. 1993; Boyles & Biondo 1993; and others). A few of the multitude of sonar array applications include passive listenning arrays for submarine detection. Marine biologists use similar arrays in tracking animal life such as whales. Geologists are able to detect submarine movement of magma and seabed materials. Oceanographers make extensive use of both vertical and horizontal seafloor arrays to study surface waves (Davis et.al. 1997), accoustic propagation speed in various shallow-water areas (Boyles & Biondo 1993), high-resolution mapping of the ocean floor, and seasonal temperature changes.

Side-scan sonar imaging

Certainly one of the more profitable areas of underwater acoustics, it is also one with huge numbers of applications. This technology is frequently used by archeologist, geologists, prospectors and developers, not to mention search-and-rescue teams and practically anyone else who wants to explore the sea-floor. Indeed, high quality side-scan units are commercially available now for a modest price.

The typical side-scan sonar is a short array (typically 50 wavelengths long) encased in a *towfish*, a torpedo-shaped object towed underwater behind a ship. It typically operates in the hundreds of kilohertz range providing good azimuthal and range measurements. The high frequency limits it to operating in fairly shallow water (a hundred meters). (Figure 3.xxx)

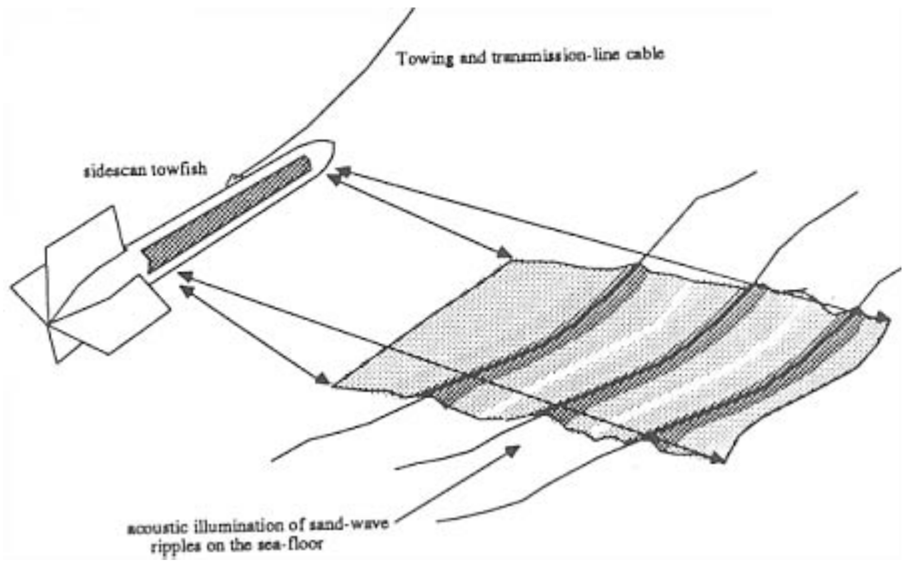

Figure 3.10: Side-scan sonar system. The towfish is typically a meter or so long (Coates 1989).

As the towfish is pulled through the water, it emits a sonar pulse in a fan-pattern covering the line of a seabed. The strength of the return plotted against the delay in response can then be interpretted as the illumination of a source as a function of distance. Subsequent pulses give the next lines in what soon becomes a 3-dimensional image. Strong signals belie something strongly ``illuminated'' while areas of little or no signal are ``shadows.'' Figures 4 and 5 contain illustrations of these images.

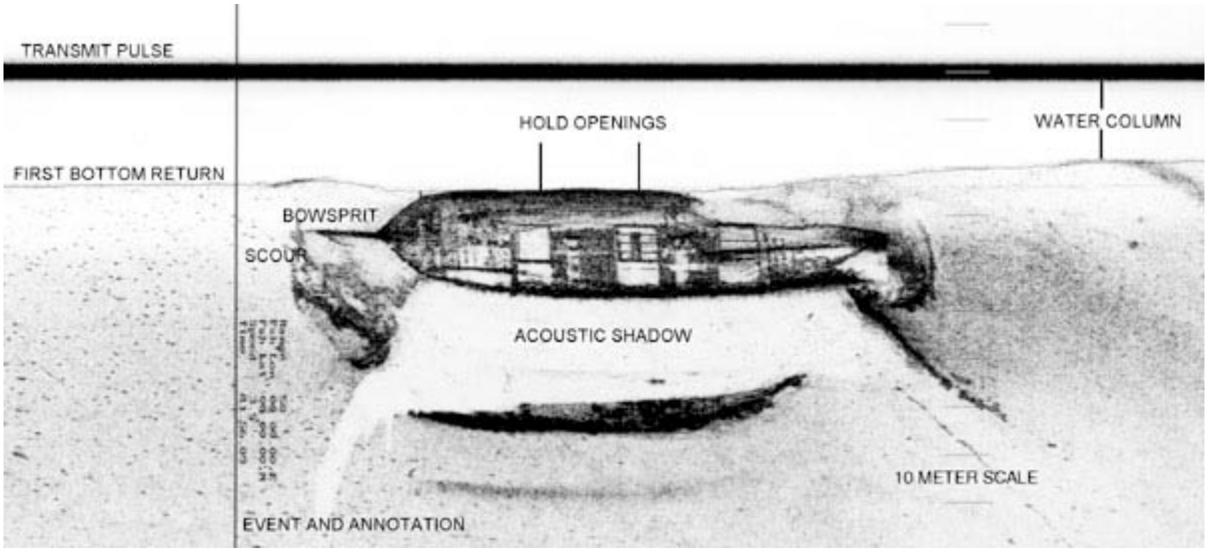

Figure 3.11: *Side-scan sonar image of a wreck (KleinSonar, 1997)*

Figure 3.12: *Side-scan sonar image of seafloor geology (KleinSonar, 1997)*

Passive Listening Arrays

The world's navies are constantly engaged in a race to make their submarines stealthier and at the same time, develop better methods of detecting enemy vessels. Davis et al. (1997) advanced the technology of detection of moving vessels. They developed and used a passive, two-dimensional array layed on the ocean floor for measuring ambient sound in the frequency range of 0.01 to 6000-Hz. This array was connected by fiber-optics to a central telemetry station Tests of the system indicated that passing ships could be detected. Similar arrays feature the capability to monitor the height of surface waves (variations in the height/depth of the water results in fluctuations of pressure with at depth) and marine life.

A different approach to the same challenge was developed by Lombardo et al. (1993). Their approach involved the development of a twin-line towed array. This 5-km twin-line array was towed behind a ship in deep waters south of Hawaii. Using careful beamsteering and nulling, they were able to scan the acoustic environment and resolve the location of individual surface ships located at distances remote to the array.

Air-based acoustic arrays

It is no surprise that practically all acoustic arrays operate underwater. There are several reasons for this. Gases unlike denser media such as water are not good conductors of acoustic energy. The variations in the temperature of air are more extreme and change more rapidly than those in water and result in variations in the refraction systems. Finally, other sensing systems, such as radar and simple visual observation, have the capability to operate in air while they are less effective in marine environments.

An interesting non-marine application of passive accoustic arrays is found in a series of military listening posts scattered across the American Southwest (Hoffman 1996). Originally intended to detect the extremely low freqency accoustic (infrasound) signatures of atomic weapon tests, it has proven useful in tracking large meteorites that enter the earth's atmosphere.

3.5.11 Biomedical Applications

Acoustical Properties:

With the exception of lung, bone and fat, the tissues of the body have acoustic impedances that differ by only a few percent from that of water. Their small-signal absorption coefficients appear to be largely a function of their macromolecular composition. The total attenuation of an acoustic wave includes energy losses (absorption) and losses from diversion of the wave from its path (scattering). For most soft tissues, scattering is relatively small and the attenuation and absorption coefficients are approximately the same. As explained by Dunn (1974); Pedersen and Ozcan (1986); and Hartman et al.(1992), the lung has the highest attenuation coefficient of any of the tissues of the body, and the attenuation seems to be almost entirely from scattering. Bone has the highest absorption of the body tissues (>100 Np/m at 1-MHz).

Small concentrations of gas dispersed in the form of micrometer-sized gas bodies can have a dramatic effect on the acoustical properties of the medium. Bubbles near resonance size for the frequency of the sound seem to have absorption and scattering cross sections that are many times greater than that expected on the basis of their physical size. Also, it has been observed that for such a medium, the absorption and cross sections can be many times greater than that measured for the same medium with no bubbles. Little research has been undertaken in this area and no systematic studies of tissues from this perspective have been reported. It is known that certain specialized tissues, such as insect larvae and the leaves of the aquatic plants contain stabilized gas bodies that are associated with their respiration.

It is also observed that the ultrasonic echoes from most tissues are small relative to the transmitted signal amplitude. As a result, imaging equipment requires high output pressure levels to achieve a reasonable signal-to-noise ratio in the image. In developing an understanding of nonlinear effects across the wide range of medical applications, it is useful to have a means of characterizing the degree of nonlinear distortion of the wave at any given position in the field. There are also some other effects of these acoustic scattering and absorption like the absorption of sound leads to heat generation in the acoustic medium. Specifically, the rate of heating (in mechanical units) is equal to the negative divergence of the local acoustic intensity, which for a small signal plane wave is proportional to the product of he absorption coefficient of the medium and the local intensity information of temperature.

By taking into account all the above acoustic applications, it should be noted that there is another side to acoustics and its application. A study of cavitation noise in different frequency bands as a criterion for the onset of acoustic cavitation has been undertaken. The results by this method are compared with those obtained using other criteria for the onset of cavitation. The spectral intensity distribution of the noise in tap water and in sea water in the frequency range 300-c/s to 500-kc/s(c/s–cycles/second) has been determined under free field conditions using a hydrophone of known response. The resulting spectrum contains a number of harmonics and subharmonics of the exciting frequency superposed on a broadband. The results are discussed on the basis of the excitation theories on the dynamics of cavitation bubbles in an acoustic field.

CHAPTER 3.6

FUTURE OUTLOOK

So far the acoustic engineering has been discussed in detail along with its applications in various fields. It is equally important to see the future perspective of acoustics in those fields. This chapter gives directions in which the future research are focused with regard to acoustic engineering. The main concentration is toward acoustic applications in the oil industry.

The effect of sonication on removal of petroleum hydrocarbon from contaminated soils by soil flushing method was analyzed at The Pennsylvania State University in 2000 by Young, K. U. This study has provided an in-depth understanding of the effect of sonication on contaminant removal from soils. Although the range of test conditions including soil types, density levels, flow rates, temperatures and energy levels of ultrasonic waves are reasonably broad, there still are factors which need to be investigated before a generally accepted in-situ cleaning methodology can be developed. In order to develop this study in future, the following considerations are stated,

- A further study under a much broader soil and hydraulic flow conditions is needed. The test soils should have varying density, gradations and particle shape. For each soil condition, the test should be performed under a wide range of flow rate.
- Tests with a wide range of sonication power and frequency are needed. Tests should also be conducted for varying stress wave propagation directions with respect to flow directions so that the influence of wave propagation direction on sonication effect can be evaluated.
- Large-scale and two dimensional laboratory experiments with aforementioned broad test conditions should be conducted to verify and modify, if necessary, the findings obtained from the one-dimensional laboratory study.
- The laboratory experiments should be conducted using an actual petroleum hydrocarbon. Based on the test results, the findings obtained from a surrogate contaminant can be verified and modified, if necessary, to suit the problem of real contaminants.

- To evaluate potential applications of the sonication-enhancement soil flushing method, an actual contaminated site should be selected and a field test conducted.
- An analytical method, which does not require a preliminary analysis of stress wave distribution, should be developed for evaluating the effectiveness of the soil flushing method with sonication.

The effectiveness of ultrasonic waves in removing wellbore damage was investigated at laboratory scale at The Pennsylvania State University by Ozdemir, M. Y, et al. in 2004. The results have shown that sonic stimulation was more effective in co-current direction and the combination of sonic stimulation with the solvent did not create a significant improvement in the permeability value. It is recommended that in the future, solvents other than ethanol be used to determine the combined effect of solvent and sonic stimulation. In their study, liquid permeability measurement, which was comprised of three steps (before, during and after), was done continuously. In this way the effect of solvent and sonic stimulation alone could not be independently determined. In future work, the gas permeability measurement should be carried our after each step (before, during and after). In this way the separate effects of solvent stimulation and sonic stimulation can be determined. A study may also be carried out to establish the relationship between the critical surface tension of wetting and the measured liquid permeability values.

Acoustic Harmonic Generation by Microstructures

Future Program Directions:

- Investigate the source of striking differences in the elastic scattering losses in cast materials and materials produced by powder metallurgy with similar grain sizes. Investigate samples made from powder with varying degrees of surface oxidation to reduce the intergranular correlation.
- Conduct first-principles calculations of third-order elastic constants for one of Cu-Al or Al-Cu alloy systems to quantitatively determine the impurity effect on harmonic generation.

Interactions with other programs

Collaborative interactions with Ames Laboratory: Results of this program are important to the PNGV Program and the Advanced Automotive Technologies Program, as well as the Material Processing User Center (M-Plus) at Oak Ridge National Laboratory. The theoretical effort will modify and utilize the parallel local self-consistent multiple-scattering computer code developed under the materials science section of the Grand Challenge Program. The goals of the research were identified as first-priority items at the DOE/BES/EPRI Workshop in Charlotte, NC, and by the Energy Infrastructure Integrity Initiative of BES/DOE.

The microstructural changes that accompany aging and degradation in metals and other structural materials occur on a size scale (20-200 nm). This size scale is very small with respect to the dominant elastic wave scatter in these materials. For this reason, traditional nondestructive evaluation (NDE) techniques have shown little potential for monitoring the evolution of degradation in this important class of materials. However, the introduction of defects (vacancies, voids, dislocations, precipitates, etc.) into the atomic lattice has been shown to increase the elastic nonlinearity of materials, often several-fold, thereby offering a possible nondestructive means of monitoring the formation and evolution of degradation. This program seeks to understand the fundamental mechanisms of the nonlinear interaction of elastic waves with the microstructure. The effects of the various contributions to material degradation are being quantified through first-principles calculations of the changes in lattice anharmonicity in the presence of defects; development of elastic field models that connect these small-scale changes to the continuum response; and experimental verification of the predicted changes [16-18].

Little is known of the precise manner in which various microstructural defects evolve to produce features detectable by traditional NDE techniques and, ultimately, failure. In particular, early-stage microstructural changes, the point in the evolution of degradation at which repair methodologies can be applied most effectively, are currently detectable only by destructive techniques. By studying the interaction of elastic waves with each class of microstructural change, we seek to advance understanding of the manner in which these changes evolve and the relative importance of each to overall degradation. In order to advance this understanding most effectively, it is important to combine both theoretical and experimental investigations of elastic wave interaction with each contributing microstructural feature. The former provides guidance to the latter and tests our understanding of the physics involved, while the latter validates the former and can uncover inadequacies in the theory. It is also necessary to study systems of sufficient simplicity to allow separation of the effects of each microstructural feature and to permit a full understanding of the contribution of each feature to overall degradation before introducing the contributions of additional features.

Most of the key environmental sources of sound: wind, rain and sea-ice and waves; are readily monitored in near real-time via satellites. Thus with the aid of a suitable assimilating model one should be able to predict the presence of these sources and infer their likely contributions to the underwater sound field. This section will discuss the capability of current satellite sensors and models, highlighting the causes of the greatest uncertainties.

There is continuing interest in the understanding and prediction of the underwater sound levels due to environmental contributions. These provide a background noise level limiting the ability to monitor cetaceans, detect man-made vessels or exchange sub-sea information via acoustic telemetry. To design systems for these aforementioned purposes one needs to know the likely acoustic spectrum due to all the natural features. This can be gained from knowledge of all the source terms and the propagation conditions. Some of these aspects are constant or slowly-changing, and so the relevant terms are readily supplied from a climatic database; some change fairly frequently and therefore need regular updates from satellites or other monitoring systems, while others change significantly on such short time scales that assimilating models are required to provide the most appropriate estimates. The next section provides a summary of the natural acoustic sources in the open ocean and the sound levels generated, while Section 3 provides an overview of the current monitoring/modelling capabilities.

Summary of sources and spectra

Wind is almost omni-present, and its acoustic signature is typically discernible. Wind generates subsurface sound through the generation of small bubbles in the sea water. Although the generation of bubbles ('whitecapping') appears to commence once the wind speed exceeds ~5 ms-1, bubbles are present in small amounts with the slightest winds. The typical acoustic spectra generated by wind increase with wind speed and fall off with frequency. Rain generates sound in a variety of ways, involving both the direct impact on the surface and the creation of sub-surface bubbles. The small raindrops in a drizzle produce a characteristic peak around 14-kHz, while the acoustic signature of heavy rain differs from wind in both the spectral slope and the acoustic intensities achieved. Different spectra again are ascribed to hail and snow. In polar climates sea-ice can be an important contributor to the sound field through a number of mechanisms. For example, there is the daily cycle of warming and cooling which leads to "microfracturing", as well as the jostling of neighboring ice parcels which is dependent upon the magnitude and direction of the wave field. On the other hand, sea-ice reduces the direct generation of sound by wind. Whales, dolphins and porpoises create a wide range of sounds, covering frequencies between 20-Hz and 20-kHz. A number of other creatures, such as croaker fish and snapping shrimp generate significant volumes of sound in certain frequency ranges. The snapping shrimp are common in many shallow warm (tropical) waters. As well as the source terms, it is necessary to know the local propagation conditions, which depend upon the depth of interest, the sea bottom type and the sound speed profile. The nature of the ocean floor is important in that it may increase acoustic intensity at some frequencies through the reflection of sound. The stratification of the water column may have a marked effect on the refraction of sound rays from distant sources. And finally, the recent meteorological history may have an effect, as both strong winds and heavy rain produce a sub-surface bubble layer that attenuates the higher frequencies generated by any subsequent surface sources.

Monitoring the sources

Much effort has been expended on global monitoring of wind speed by satellites, with algorithms existing for data from altimeters, scatterometers and passive microwave radiometers. Numerical weather prediction models can assimilate past observations to give an accurate estimate of current wind speed, and also provide forecast for several days ahead. While rain can be detected by a number of spaceborne sensors (altimeters, passive microwave radiometers and infra-red sensors), there are large errors in their accuracy. The assimilation and prediction of rain in models is presently an active area of research. Also rain changes on short spatial and temporal scales and bulk averages of the rain rate are not very useful in this context. In many locations, a large fraction of the observations of rain indicate rain rates of 1-mm h-1 or less. Such low rain rates are poorly detected by many satellite sensors, yet are important because their acoustic contributions can be loud and very distinct from that of heavy rain. At the other extreme, the extent of sea-ice changes slowly (over periods of weeks). The thermal microfracturing is controlled by latent heat loss; monitoring of cloud cover acts as a proxy for this. At present the biological sources are best determined from climatologies of observations; however, monitoring of temperature coupled with knowledge of bathymetry could provide an improvement in the seasonal changes in snapping shrimp. Observations of chlorophyll by ocean color sensors may be used to indicate the likely feeding zones in the complex marine food web.

The way forward

Many of the building blocks for a global acoustic prediction scheme are present. The typical spectra of the environmental sources are fairly well known (although still an area of investigation), and models have been developed to assimilate the frequent wind observations from a number of sensors. The effect of different bottom types is a factor yet to be fully assessed. For many locations and applications, wind information might be sufficient for acoustic predictions. However, to be useful for defense purposes, improvement is needed for locations/occasions when rain, sea-ice or various noise-generating life-forms are present. There is still much work required to model these processes with sufficient accuracy.

Summary

Acoustic Engineering has been discussed in detail including its applications in various fields of Engineering. The applications are concentrated towards oil industry in particular. This report is a collection of work done by many research institutes, some of which are provided in the bibliography section. Please contact the authors for further information about any specific topic or research material. Sonication research at Penn State University has been a great contribution to the progress of Acoustic Engineering.

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